DRILLING OPTIMIZATION USING DRILLING SIMULATOR SOFTWARE

A Thesis

by

JOSE GREGORIO SALAS SAFE

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

May 2004

Major Subject: Petroleum Engineering

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Approved as to style and content by:

Hans C. Juvkam-Wold (Chair of Committee)	Ann E. Jochens (Member)
Jerome Schubert (Member)	Hans C. Juvkam-Wold (Interim Head of Department)

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ABSTRACT

Drilling Optimization Using Drilling Simulator Software.

(May 2004)

José Gregorio Salas Safe, M.I., Universidad Central de Venezuela, Venezuela

Chair of Advisory Committee: Dr. Hans C. Juvkam-Wold

Drilling operations management will face hurdles to reduce costs and increase performance, and to do this with less experience and organizational drilling capacity. A technology called Drilling Simulators Software has shown an extraordinary potential to improve the drilling performance and reduce risk and cost.

Different approaches have been made to develop drilling-simulator software. The Virtual Experience Simulator, geological drilling logs, and reconstructed lithology are some of the most successful. The drilling simulations can run multiple scenarios quickly and then update plans with new data to improve the results. Its storage capacity for retaining field drilling experience and knowledge add value to the program.

This research shows the results of using drilling simulator software called Drilling Optimization Simulator (DROPS®) in the evaluation of the Aloctono block, in the Pirital field, eastern Venezuela. This formation is characterized by very complex geology, containing faulted restructures, large dips, and hard and abrasive rocks. The drilling performance in this section has a strong impact in the profitability of the field.

A number of simulations using geological drilling logs and the concept of the learning curve defined the optimum drilling parameters for the block.

The result shows that DROPS® has the capability to simulate the drilling performance of the area with reasonable accuracy. Thus, it is possible to predict the drilling

performance using different bits and the learning-curve concept to obtain optimum drilling parameters. All of these allow a comprehensive and effective cost and drilling optimization.

DEDICATION

To my parents, Maxima and Melecio, for your total love and support in my life,

To my wife, Annellys, for your companionship and love in the life's adventure,

To my daughters Laura and Daniela who helped, supported and gave me hope for the future,

To my sisters and brothers, my unconditional friends,

And to my friends Cesar, Carlos (El Tío), Ernesto, Felix, Marilyn, Adriana, and Mariela for the friendship we share… You made this degree a lot of fun.

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I would like also to thank my committee members for helping me throughout this research.

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INTRODUCTION

Drilling is one of the most expensive operations in oil exploration and development. The experience level of the drilling operations decision maker as well as the drilling contractor and support labor is sometimes low. Personnel turnover and the new sociological climate toward work can cause operational problems that previously did not exist. Exploration in more-hostile environments, more-complex well programs, deeper wells, and environmental pressures all contribute to the increase in drilling costs.[1] New, sophisticated equipment is being used on some rigs, adding more overall costs to the drilling operation.

Other industries facing a similar dilemma-aerospace, airlines, utilities, and the military-have all resorted to sophisticated training and technology-transfer methods by means of different types of simulators, training to compress the experience curve and to transfer current technology. Examples of this are the training of fighter and commercial pilots using aircraft simulators. The power-generation industry regularly uses simulators to train plant personnel in the operation of fossil fuel and nuclear plants.[1]

Millheim[1,2] defined a simulator as a device or piece of equipment that replicates some physical process or operation to some level of fidelity. Simulation is not related to equipment and is the numerical or logical replication of some process, operation, or phenomenon.

This thesis follows the style of *SPE Drilling & Completion*.

The oil industry and specifically the drilling industry have not tapped the potential of simulator technology.[1,3-5] The simulators are being used only to teach conventional well control. This not only reflects the lack of insight on proper simulator use in training, but also implies that currently designed simulators do not have the flexibility and fidelity to replicate the drilling process well enough to structure a training program around them.

New drilling simulators are being developed with state-of-the-art simulation technology. Millheim and Gaebler[3] presented a new concept based on heuristics to create a heuristic computer simulation device and what they called Virtual Experience Simulation (VES) for drilling. They show how they used data available for 22 drilled wells to develop a simulator with the capacity for reproducing the drilling performance observed in the drilled wells.

Cooper *et al.*[4,6,7] describe a drilling simulator software built around a drilling-mechanics model that predicts the rate of penetration and rate of wear of a drillbit as a function of type of bit, the rock being drilled, and the set of operational parameters.

A different approach to build a drilling simulator was presented by Rampersan, Bretli and Hareland,[8-10] who developed their DRilling OPtimization Simulator (DROPS®) based on Geological Drilling Log (GDL) and data collected from a previous well drilled in the same area.

This research extends their efforts to describe the advantages, disadvantages, and accuracy of the DROPS® software using real field data. Simulations made with data from the Aloctono block, Pirital field, eastern Venezuela, showed how simulating changes in operational parameters, and types of bits can identify the optimal result and generate recommendations to improve the actual performance in the area.

DRILLING SIMULATOR

DEFINITION

A simulator is defined as a device or piece of equipment that replicates some physical process or operation to some level of fidelity. Reliable drilling simulator software can replicate the drilling process with a close level of fidelity. Different simulations with different parameters can identify the optimal results. There are different approaches as to how to build drilling simulator software; some of the most important are discussed below.

VIRTUAL EXPERIENCE SIMULATION FOR DRILLING

Also called *heuristic simulation*, Virtual Experience Simulation for Drilling (VESD), presented by Millheim and Gaebler in 1999, is based on the development of activated data sets for actual wells. The oil industry is faced with the challenges of improved drilling performance and cost without the benefits of localized drilling experience, although huge amounts of accumulated data are available from the wells drilled in the past. This data accumulation allows the heuristic simulation to be developed and used,[3] but these "inert data" need to be converted into retained knowledge and potential learning. Various behaviors, events, and situations throughout drilling a sequence of wells constitute "lessons learned" that can be recognized and kept for appropriate applications.

One example of how the data can be activated is illustrated with the estimation of the tripping time. In generic drilling simulators, the calculation of the tripping rates is usually done by a constant factor for running in the hole and pulling the drillstring out of the hole. Between 1988 and 1997, Milheim and Gaebbler[3] used a different approach by calculating the tripping rates of 18 drilled wells in a field as a function of depth. To generate the tripping times as function of total depth drilled, they collected tripping data and sorted them in increasing order, generating two scatter plots, one for tripping in and one for tripping out of the hole, as shown in **Fig. 1**.

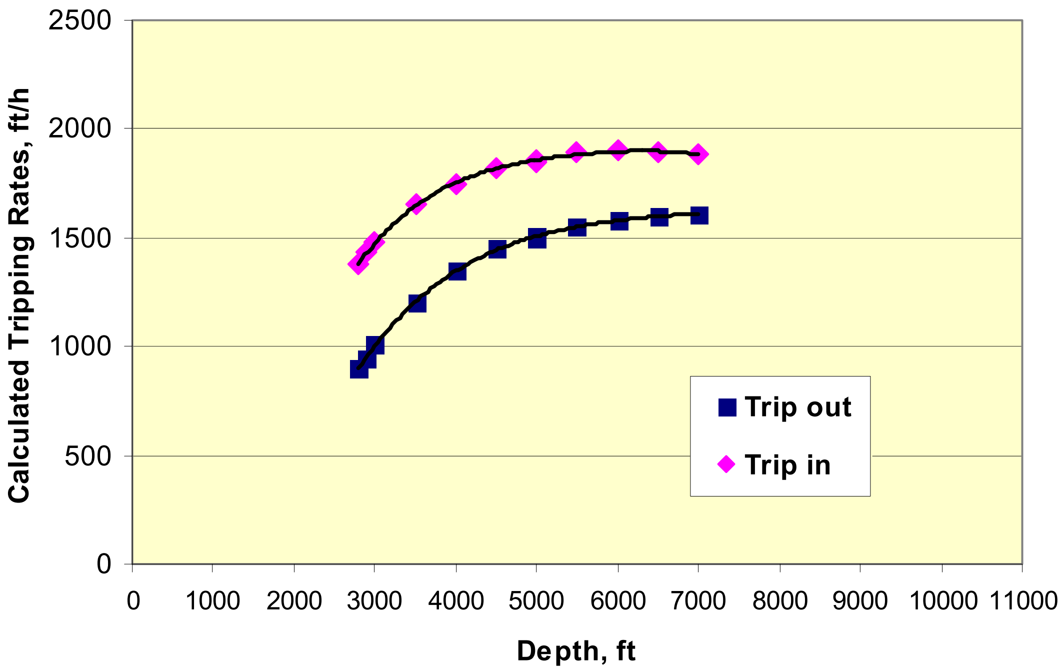


Fig. 1–Trip rate derived from actual well data shows difference for trip in and out (from Millheim and Gaebler[3]).

Using these plots and the statistical evaluation software Origin 5.0, they performed second order, polynomial curve-fitting calculation for each data set. The fitting function given by Eq. 1 resulted in the parameters listed in **Table 1**.

$$\text{Trip Rate} = A + B \cdot \text{Depth} + C \cdot \text{Depth}^{2}. \qquad \textbf{(1)}$$

TABLE 1—PARAMETERS USED FOR THE TRIPPING RATE ESTIMATION[3]			
	A	B	C
Trip In	-266.00	0.49	-2.28×10^{-5}
Trip out	548.86	0.36	-2.87×10^{-6}

A second example of use of activated data is the estimation of rate of penetration (ROP). Using data from 12 drilled wells and taking into account the flexibility of choosing the weight on bit (WOB) and revolution per minute (RPM) as major parameters affecting the ROP, Milheim and Gaebbler[3] built a topographic map for one layer (No.15), where the ROP values were interpreted as the height. The isometric map and a 3D model were generated using Surfer V6.02 software **(Fig. 2)**.

The numerals 1, 2, 3, and 4 identify regions where the combination of ROP and WOB shows the best performance. The same type of analysis or "data activation process" can be made for each activity and parameter of the drilling operation: coring, cementing, logging, unscheduled events, etc.

From the activated data sets, Milheim and Gaebbler[3] developed a computer model called an "heuristic engine" to present the user an interactive environment to gain insights into a certain domain and test different scenarios.

The design steps and design considerations throughout the development of the VESD is basically divided into the description of the generic part and the heuristic part of the drilling model. The generic part of the drilling simulator is mainly represented by a procedural course of events which makes up the basic drilling. It is the skeleton for the subsequent heuristic part, where field-specific data are implemented into the VESD.

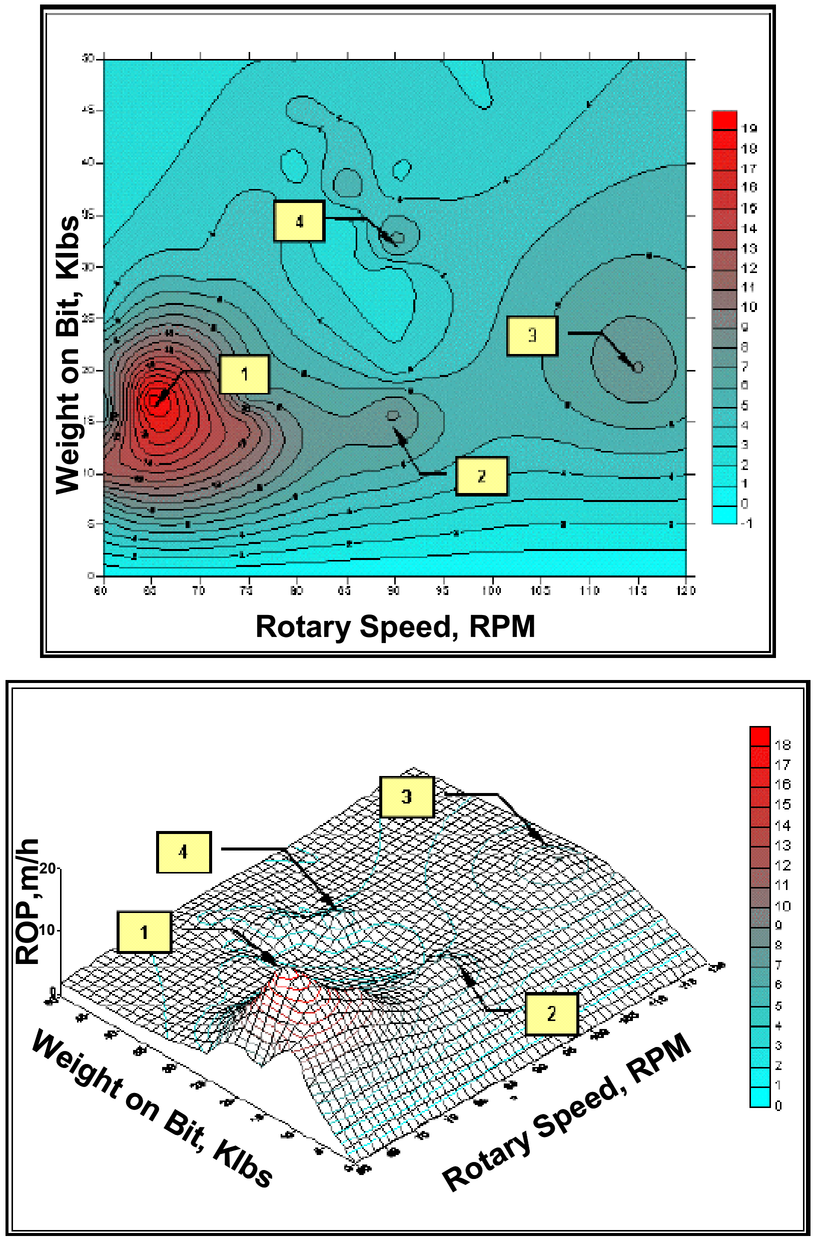


Fig. 2–Surface and 3D ROP map for Layer 15 (from Millheim and Gaebler[3]).

Fig. 3 shows the five basic processes encountered during the drilling of a well that account for more than 90% of the time spent on location.

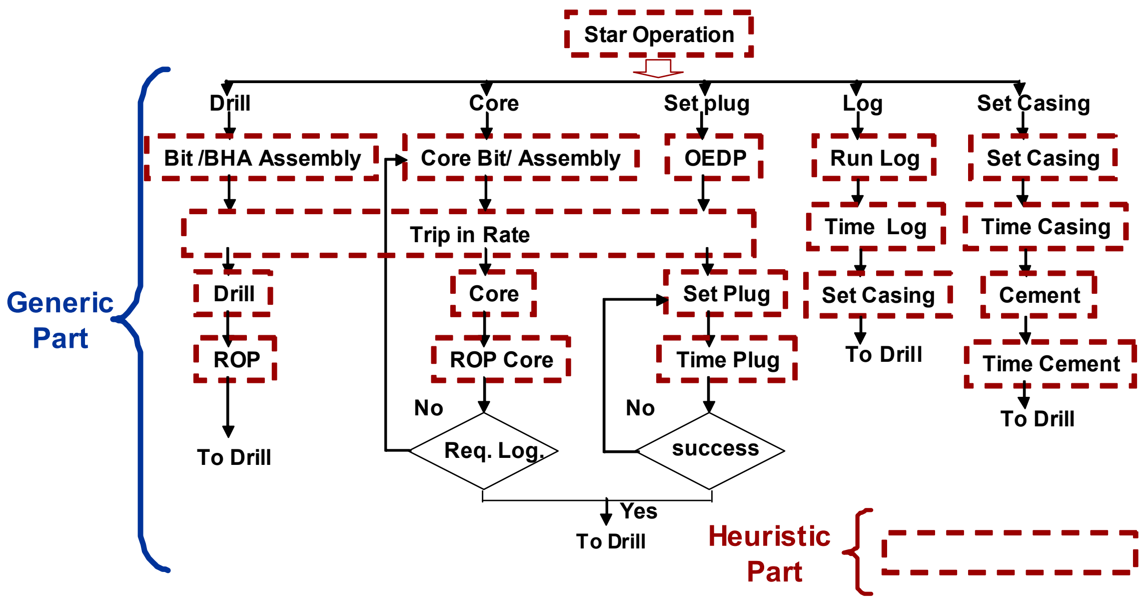


Fig. 3–VESD flow diagram (after Milheim and Gaebbler[3]).

Heuristic simulation is the bridge between the knowledge contained in activated data sets and the ability to quickly learn the previously gained insights and experience.

Advantages and Disadvantages of VESD

Because VESD is based on the use of field data, this approach does not require any use of theoretical drilling calculations. The main advantages are the availability of huge amounts of data accumulated in drilling and the possibility of learning from past experiences. The disadvantages are requirements to clean and activate the data. This is a tedious process and requires really creative work. Another disadvantage is that simulations are restricted to only previous experiences and to activity with enough statistically meaningful data.

LITHOLOGY EDITOR DRILLING SIMULATOR

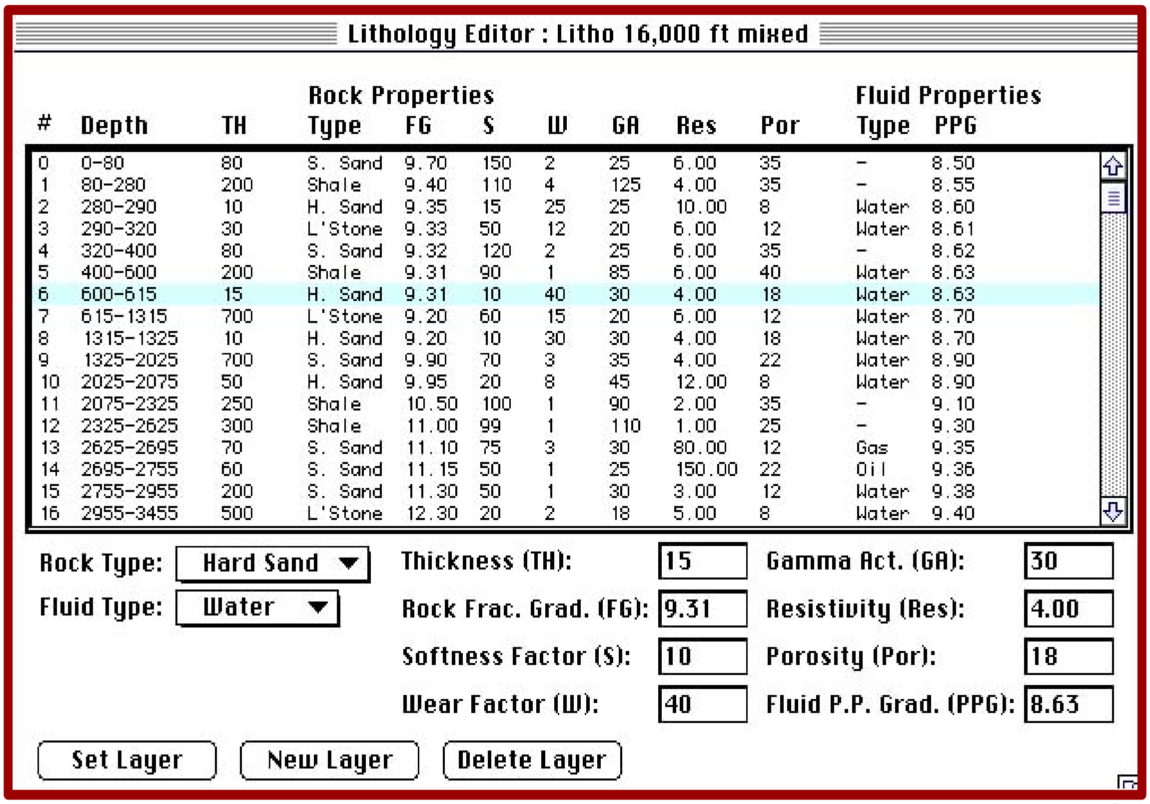
Lithology Editor Drilling Simulator (LEDS)[4-7] is based on the capability to import data from field operations. The simulator operates by taking input generated by a series of editors that specify the governing parameters of the simulator in several categories (lithology, drill bits, muds, bottomhole assembly, casings, operational constraints). These are combined into a source file, known as a *state*. The state file is used by the simulator itself to generate the drilling response.

A simulator's lithology editor has an option that allows a Log ASCII Standard (LAS) file to be imported and converted to a lithological column that the simulator can use **(Fig. 4)**. LAS files are industry-standard text files that contain log data recorded on a foot-by-foot (or metric) basis. As well as basic log data, they may contain processed data such as estimates of rock strength.

To be of value in generating a drilling response, the lithology needs, at minimum, to record the rock type, strength, and abrasivity. Rock-type data are usually available in a typical LAS file, strength data are sometimes given, but abrasivity is usually not posted. The converter has been given a capability to infer rock strength from sonic data following recommendations available in the literature, if strength data are not available[5]. However, to estimate abrasivity, it is necessary to define a way to estimate this value. An example of how the abrasivity of the formation is estimated is shown in Eq. 2,

$$\text{Abrasivity} = \text{Constant} \cdot \text{Quartz Content} \cdot \text{Rock Compressive Strength.} \quad \textbf{(2)}$$

When all the data are loaded, the simulator is adjusted to reproduce the drilling performance observed in the offset or reference well. Then any well can be redrilled to see if a better set of operating conditions can be specified. In the same way, a new well can be "drilled" and its drilling performance optimized.



#	Depth	TH	Type	FG	S	W	GA	Res	Por	Type	PPG
0	0-80	80	S. Sand	9.70	150	2	25	6.00	35	-	8.50
1	80-280	200	Shale	9.40	110	4	125	4.00	35	-	8.55
2	280-290	10	H. Sand	9.35	15	25	25	10.00	8	Water	8.60
3	290-320	30	L'Stone	9.33	50	12	20	6.00	12	Water	8.61
4	320-400	80	S. Sand	9.32	120	2	25	6.00	35	-	8.62
5	400-600	200	Shale	9.31	90	1	85	6.00	40	Water	8.63
6	600-615	15	H. Sand	9.31	10	40	30	4.00	18	Water	8.63
7	615-1315	700	L'Stone	9.20	60	15	20	6.00	12	Water	8.70
8	1315-1325	10	H. Sand	9.20	10	30	30	4.00	18	Water	8.70
9	1325-2025	700	S. Sand	9.90	70	3	35	4.00	22	Water	8.90
10	2025-2075	50	H. Sand	9.95	20	8	45	12.00	8	Water	8.90
11	2075-2325	250	Shale	10.50	100	1	90	2.00	35	-	9.10
12	2325-2625	300	Shale	11.00	99	1	110	1.00	25	-	9.30
13	2625-2695	70	S. Sand	11.10	75	3	30	80.00	12	Gas	9.35
14	2695-2755	60	S. Sand	11.15	50	1	25	150.00	22	Oil	9.36
15	2755-2955	200	S. Sand	11.30	50	1	30	3.00	12	Water	9.38
16	2955-3455	500	L'Stone	12.30	20	2	18	5.00	8	Water	9.40

Fig. 4–Example of lithology editor, with Layer 6 being edited (from Cooper *et al.*[4]).

Advantages and Disadvantages of LEDS

LEDS is based on a mechanistic model improved with the addition of field data. This simulator has the advantage that it combines theoretical drilling calculations with field data (lithology and drilling parameters). An additional advantage is that it is possible to construct any possible lithology and evaluate the drilling performance. The main disadvantage is the difficulty of predicting well and rock properties foot by foot.

Application of this kind of simulator is restricted to some special cases. Recently Abouzeid and Cooper[5] presented a field case using this simulator to optimize drilling a hydrocarbon well using data from offset wells. They found that changing the operational parameters (increasing the rotary speed while reducing weight on bit) or selecting a different type of bit (milled tooth or PDC) might obtain a better performance.

GEOLOGIC DRILLING LOG SIMULATOR

The Geologic Drilling Log Simulator (GDLS) is based in the use of Geologic Drilling Log (GDL), created from the data collected in previous wells drilled in the same area.[9] The GDL is generated from the combination of raw drilling data, data from drilling models, and geologic information **(Fig. 5)**.

The GDL is created by inversion of the drilling ROP models specific to the bit used for drilling each interval. It is designed for high-fidelity drilling simulators and consists of a matrix of drilling and geological parameters whose properties define the drilling conditions at a specific location.[8]

Because GDL contains rock strength, it is possible for GDLS to use it in a drilling model under specific conditions to determine ROP on a foot by foot basis. The GDLS allows obtaining the least cost for the interval drilled by creating the GDL from information recorded from offset wells in the field.

Applying the GDL together with bit models and the drilling parameters give the ROP at any particular depth. Then the ROPs are applied to compute the cost per foot using Eq. 3 and appropriate bits and operational costs.

$$C_f = \frac{(t_r + t_t + t_c)C_r + t_r C_m + C_b}{\Delta D} \quad \textbf{(3)}$$

The best cost of the section is calculated as shown in the **Fig. 6**. The specific operational conditions and lowest-cost drilling are then observed through the simulation.

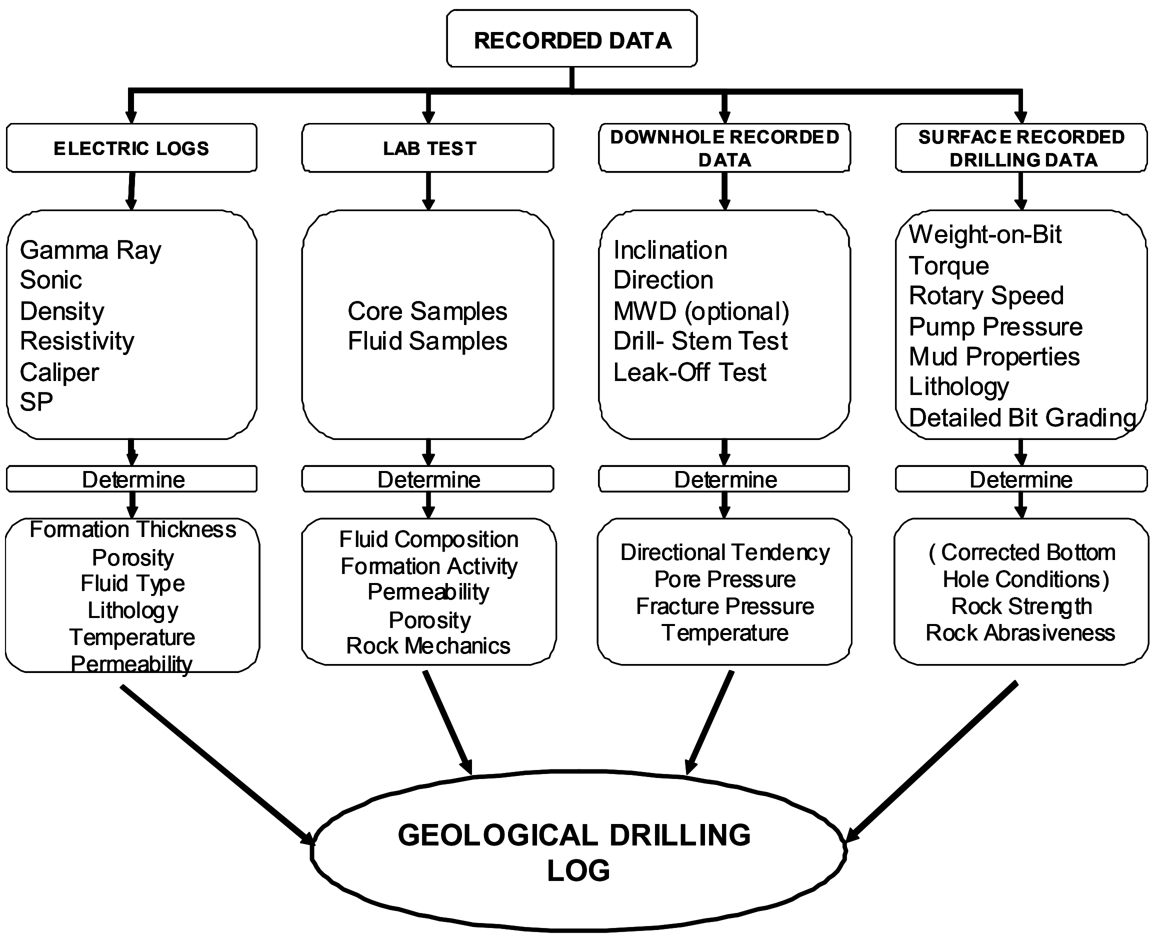


Fig. 5–Flow diagram of GDL creation (after Rampersad *et al.*[8])

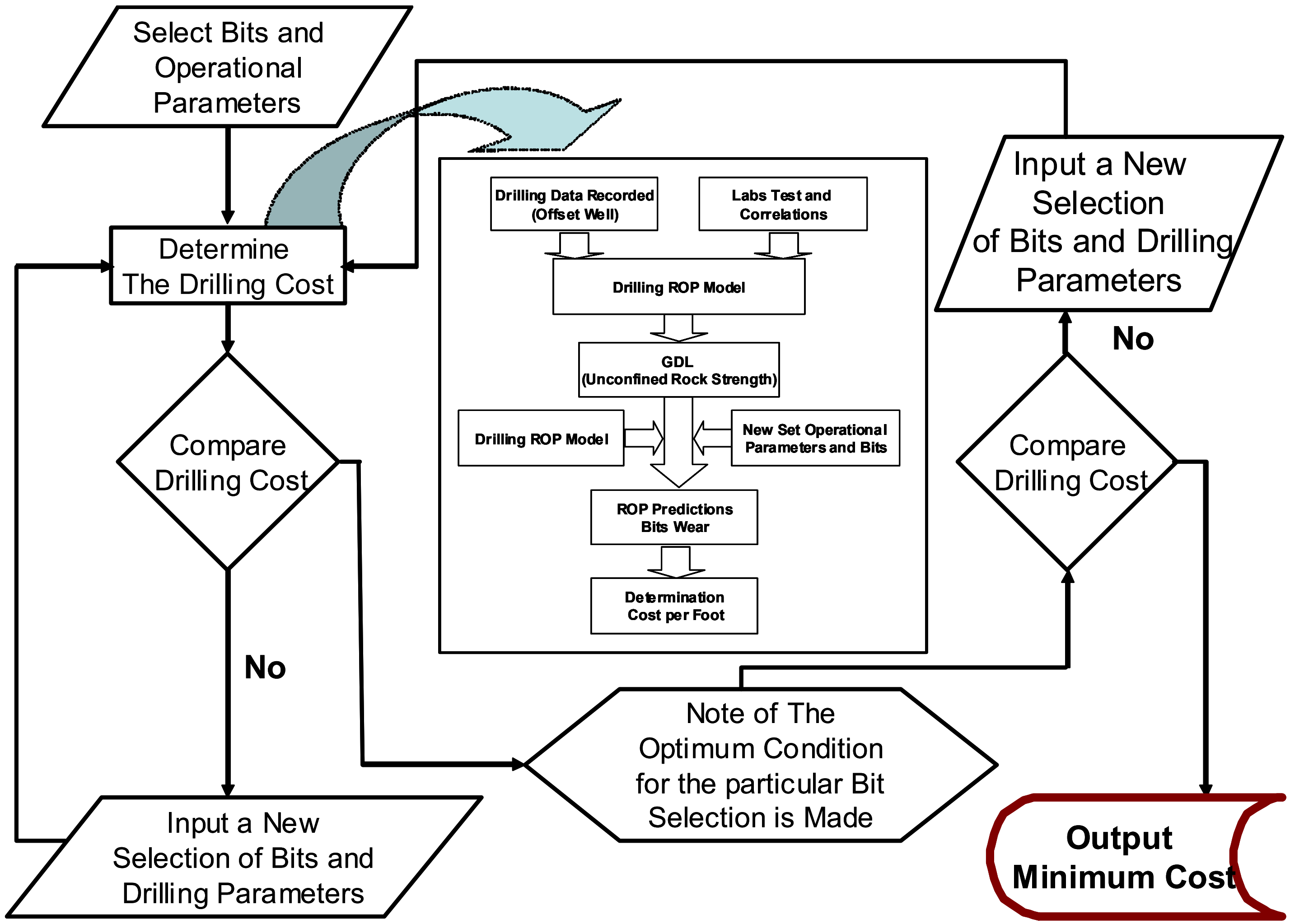


Fig. 6–Step to obtaining optimum drilling cost (after Rampersad *et al.*[8])

Rolling-Cutter Bits Model

Rolling-cutter bits, commonly called *cone bits*, have two or more cones containing the cutting element, which rotate about the axis of the cone as the bit is rotated at the bottom of the hole.[11] The three-cone bit is one of the most popular types of bit used in the drilling industry and provides a wide range of capability for drilling a wide variety of formations **(Fig. 7)**.

The drilling action of the rolling-cutter bits is a combination of scraping, twisting, and crushing the formation. The geometric disposition of the cones (offset), shape, spacing, and length of the teeth determine which mechanism is predominating.

Fig. 7–Example of three-cone rolling-cutter bits with milled and insert tooth (from Baker Hughes[12]).

A model of the drilling process for cone bits was derived by Warren[13] and later modified by Hareland[14]. The model relates ROP, WOB, rotary speed, rock strength, and bit size[14].

It is based on tests that were designed to provide basic information about the interrelation between the bit and the rock, and it accounts for the effect of the cutting generation, cutting removal, the "chip hold down effect," and the bit wear on the penetration rate.

Eqs. 4 through 9 relate penetration rates to operational condition, rock strength and bit parameters and includes the effects of hole cleaning and bit wear rate.

Eq. 4 estimates the rate of penetration of the bit.

$$\mathrm{ROP} = W_f \left[f_c(P_e) \left(\frac{aS^2 D_{\mathrm{bit}}^3}{\mathrm{RPM} \cdot \mathrm{WOB}^2} + \frac{b}{\mathrm{RPM} \cdot D_{\mathrm{bit}}} \right) + \frac{c\rho\mu D_{\mathrm{bit}}}{I_m} \right]^{-1} \quad \textbf{(4)}$$

The first term of the equation defines the rate at which rock is broken into small chips by the bit. The second term modifies the predictions to account for the distribution of the applied WOB to more teeth as the WOB increases and the teeth penetrate deeper into the rock. The third term accounts for the efficiency of the cutting-removal process based on hydraulics. Solving this Eq. 4 for *S*, the confined rock strength,

$$S = \left[\frac{\mathrm{RPM} \cdot \mathrm{WOB}^2}{af_c(P_c) \cdot \mathrm{ROP} \cdot W_f \cdot D_{\mathrm{bit}}^3} - \frac{b \cdot \mathrm{WOB}^2}{aD_{\mathrm{bit}}^4} - \frac{c\rho\mu \cdot \mathrm{ROP} \cdot \mathrm{WOB}^2}{af_c(P_c) I_m D_{\mathrm{bit}}^3} \right] \quad \textbf{(5)}$$

Eq. 6 describes the chip hold-down function which estimates the forces on a chip generated for a bit.

$$f_c(P_e) = c_c + a_c(P_e - 120)^{b_c} \quad \textbf{(6)}$$

Eq. 7 and 8 calculate the bit wear based on WOB, RPM, relative rock abrasiveness, and confined rock stress:

$$\Delta BG = W_c \sum_{i=1}^{n} \mathrm{WOB}_i \cdot \mathrm{ROP} \cdot A_{R_{ABRI}} \cdot S_i \quad \text{.......}\mathbf{(7)}$$

$$W_f = 1 - \frac{\Delta BG}{8} \quad \text{.......}\mathbf{(8)}$$

The Eq. 9 estimates the rock compressive strength as a function of the confining pressure and lithology.

$$S = S_o (1 + a_s P_e^{bs}) \quad \text{.......}\mathbf{(9)}$$

When a tricone bit is used, Eq. 5 allows calculation of the confined rock strengths, then the unconfined rock strengths can be determined from Eq. 9. The unconfined rock strengths are then confined with the pressures used in the simulation and used to calculate the ROP using Eq. 4.

Because the model is a combination of theoretical and empirical equations, a series of coefficients were developed. The coefficients a, b and c are characteristic of the bit design. **Table 2** shows an example of these coefficients for different bits.

TABLE 2—DRILLING MODEL BIT COEFFICIENTS (FROM HARELAND AND HOBEROCK[14])						
Bit Make	**Bit Type**	**Size in.**	**IADC Code**	**a hr.rpm.in/ft**	**b hr.rpm.in/ft**	**c hr.lbm.gal/ft.lb/cp.in**
Security	S33CF	8.75	116	0.0206	2.70	0.00189
Security	S82F	8.75	437	0.0182	3.07	0.00209
Security	S84F	8.75	517	0.0250	4.21	0.00355
Smith	F3	8.50	537	0.0138	9.77	0.00223
Security	M84F	8.50	617	0.0190	13.50	0.00326
Hughes	J55R	8.50	624	0.0470	13.50	0.00331
Security	H87F	8.50	737	0.0168	9.31	0.00335

The coefficients a_c, b_c, c_c, a_s, and b_s are lithology dependent constants, function of the formation permeability with values shown in **Table 3**.

TABLE 3—CHIP HOLD-DOWN PERMEABILITY COEFFICIENTS (FROM RAMPERSAND *ET AL*[8])		
$\mathbf{P_e}$	P_h-P_P	P_h
$\mathbf{a_c}$	0.0050	0.014
$\mathbf{b_c}$	0.7570	0.470
$\mathbf{c_c}$	0.1030	0.569
$\mathbf{a_s}$	0.0133	0.004
$\mathbf{b_s}$	0.5770	0.782

Drag Bit Models

All the drag bits consist of fixed cutter blades that are integral with the body of the bit and rotate as a unit with the drillstring.[11] The main drilling action of the drag bit is plowing, cutting from the bottom of the hole. The two principal types of drag bit used in the drilling operation are Polycrystalline Diamond Compact (PDC) bits and Natural

Diamond (ND) bits. A drag-bit model was proposed by Hareland and Rampersand[15] in 1994. The model is based on theoretical considerations of a single cutter rock interaction, lithology coefficients and bit wear.[8,14-16]

PDC Bit Model

This drilling tool uses synthetic polycrystalline diamond cutter (PDC) disks, about 1/8 in. thick and about 1/2 to 1 in. in diameter, to shear rock with a continuous scraping motion. The artificial diamond provides the cutter with the type of resistance needed for drilling hard rock. The diamond is bonded on the front of a tungsten carbide stud. PDC matrix bits have the cutters directly brazed into the bit body. Alternatively, PDC steel bits use PDCs mounted on studs that are pressed into holes in the bit body **(Figs. 8 and 9)**.

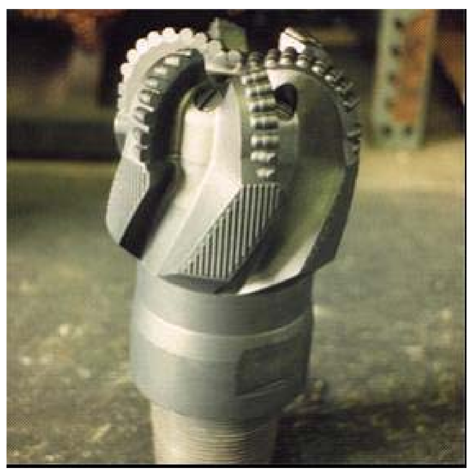


Fig. 8- Example of PDC matrix bit (from Schlumberger[17]).

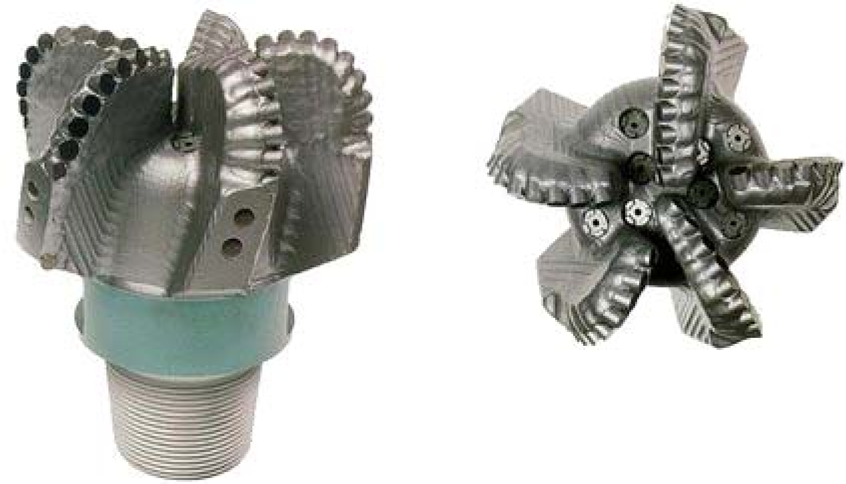


Fig. 9- Example of PDC steel bit (from Smith Bits[18]).

The model for PDC bit is based on detailed PDC bit cutter information. The PDC-bit ROP equations can be used to predict the confined rock compressive strength:

$$S = \frac{W}{N_c A_p} \qquad \textbf{(10)}$$

$$A_p = \sin\phi\left[\left(\frac{d_c}{2}\right)^2 \cos^{-1}\left(1.0 - \frac{2P}{d_c\cos\phi}\right) - \left(\frac{Pd_c}{\cos\phi} - \frac{P^2}{\cos^2\phi}\right)^{1/2}\left(\frac{d_c P}{2\cos\phi}\right)\right] \qquad \textbf{(11)}$$

$$R_e = \frac{D_{\mathrm{bit}}}{2\sqrt{2}} \qquad \textbf{(12)}$$

$$A_v = \cos\alpha\sin\theta\left[\left(\frac{d_c}{2}\right)^2 \cos^{-1}\left(1 - \frac{2P}{\cos\theta\cdot d_c}\right) - \left(\frac{d_c P}{\cos\theta} - \frac{P^2}{\cos^2\theta}\right)^{1/2}\left(\frac{d_c P}{2\cos\theta}\right)\right] \qquad \textbf{(13)}$$

$$\text{ROP} = \frac{14.14 N_c \text{RPM} \cdot A_v}{D_{\text{bit}}} \quad \text{(14)}$$

When a PDC bit is used, Eq. 14 calculates the volume removed for each PDC cutter (A_v), and then using Eq. 13 and the concept of equivalent bit radius (Eq. 12), the penetration of the PDC cutter can be determined. The penetration of each PDC is used in Eq. 11 to estimate its projected contact area. Using Eq. 10, the uniaxial compressive rock strength (S) can be calculated. The wear state of the bit is again calculated using Eq. 7 and 8.

<u>ND Bits Model</u>

Natural Diamond Bits (NDB) use natural diamonds as cutting elements. The face or crown of the bit consists of many diamonds set in a tungsten carbide matrix[11] **(Fig. 10)**. The size and number of the diamonds used in a bit face depend on the hardness of the formation to be drilled.

Fig. 10- Example of ND bit (from Smith Bits[18]).

The NDB model proposed by Rampersand *et al.*[8] works on the principle that for a given applied weight on each diamond, the bit will penetrate the rock a certain depth depending on the size of the diamonds. When the bit is rotated, it will scrape the rock, thereby removing it. As the diamonds cut the rock, a flat wear area is formed on the diamond, reducing its penetration. If the penetration is reduced, the bit removes less rock and ROP decreases. The following equations describe the most important parts of the model.

The Eq. 15 defines the mechanical WOB;

$$\mathrm{WOB}_{\mathrm{mech}} = \mathrm{WOB}_{\mathrm{applied}} - \Delta p A_p \text{ , } \qquad \textbf{(15)}$$

here

$$\Delta p = \frac{\mathrm{GPM}^2 \cdot \rho}{12031(KA)^2} \qquad \textbf{(16)}$$

KA is the bit apparent nozzle area.

The concept of equivalent bit radius is defined as

$$R_e = \frac{D_{\mathrm{bit}}}{2\sqrt{2}} \qquad \textbf{(17)}$$

Eq. 18 estimates the volume worn by each cutter per bit revolution:

$$V_d = C_a \sum_{i=1}^{n} \frac{\mathrm{WOB}_{\mathrm{mech}_i} \cdot \mathrm{ROP} \cdot A_{R_{ABRI}} \cdot S_i}{N_s \cdot R_e} \qquad \textbf{(18)}$$

WOB_{mech} represents the original mechanical WOB.

Eq. 19 calculates the penetration of each diamond:

$$P_d = \frac{2}{\pi d_s}\left(\frac{\mathrm{WOB}_{\mathrm{mech}}}{S \cdot N_s} - \frac{\pi P_w d_s}{2}\right) \qquad \textbf{(19)}$$

Eq. 20 estimates penetration loss due to wear of diamond;

$$P_w = \sqrt{\frac{2V_d}{\pi d_s}} \qquad \textbf{(20)}$$

The front projected area of each diamond can be calculated using Eq. 21:

$$A_v = \left(\frac{d_s}{2}\right)^2 \cos^{-1}\left(1 - \frac{2P_d}{d_s}\right) - \sqrt{d_s P_d - P_d{}^2}\left(\frac{d_s}{2} - P_d\right) \qquad \textbf{(21)}$$

The projected area of the worn section of a diamond can be calculated using Eq.22:

$$A_{vw} = \left(\frac{d_s}{2}\right)^2 \cos^{-1}\left(1 - \frac{2P_w}{d_s}\right) - \sqrt{d_s P_w - P_w{}^2}\left(\frac{d_s}{2} - P_w\right) \qquad \textbf{(22)}$$

The ROP for NDB can be calculated as

$$\mathrm{ROP} = \frac{14.14 N_s \cdot \mathrm{RPM} \cdot (A_v - A_{v_w}) \cdot \mathrm{corr}}{D_{\mathrm{bit}}}, \qquad \textbf{(23)}$$

here a lithology correction factor is defined as

$$\text{corr} = \frac{a_d}{\text{RPM}^{b_d} \cdot \text{WOB}^{c_d}} \quad \text{(24)}$$

The individual correction factors were developed from lab and/or field drill-off tests using nonlinear regression analysis for a specific lithology. **Table 4** shows an example of list of coefficients developed using a 6¼–in. bit in Cartoosa shale and Carthage limestone; these coefficients can be used for any NDB in these lithologies.

TABLE 4—NATURAL DIAMOND BIT CORRECTION FACTORS (FROM HARELAND AND HOBEROCK[14])

	Catoosa Shale	Carthage Limestone
a	185.4	63.6
b	0.8250	0.540
c	0.8190	0.585

Advantages and Disadvantages of GDLS

GDLS takes advantage of the capability of predicting the drilling performance as a function of rock strength. Onya[19] showed that it is possible to obtain a description in sufficient detail of the properties of the rocks from drilling data. The simulator combines the drilling data and field correlations to estimate apparent rock strength. This approach has the advantages that it is possible to obtain a realistic drilling performance simulation and good agreement with the pre-existing data. Bratli et *al*.[9] present a field case from the North Sea where the prediction of a commercial GDLS was verified.

DROPS® DRILLING SIMULATOR

DEFINITION

The DROPS® simulator is a computer program designed to facilitate the reduction of the drilling cost for oil companies.[20] It is based on the capability to simulate the drilling performance as a function of the rock strength. The Apparent Rock Strength Log (ARSL) is a representation of the apparent rock strength in a particular well or section, derived from the actual historical drilling data. The ARSL is created by using ROP data reported from the field. The depth and lithology parameters influence the ROP; therefore, they have a strong impact on the ARSL **(Fig. 11)**.

Once the program has generated the ARSL, it verifies its accuracy according to the relevant theoretical ROP models by performing a drill-behind. The drill-behind conducts a reverse-ARSL calculation, where the calculated apparent rock-strength is used to calculate the theoretical ROP; this ROP is then compared to the field-reported ROP.

Both the ARSL creation and the drill-behind are automatically performed by the program. The program will not require the user to interact in any other way than to prepare the input files needed. When an ARSL has been generated and professionally verified for its accuracy, the planning of the drilling of any new well is facilitated through its availability. With these data the drilling simulator can test different makes as well as geometrical and hydraulic properties of drill-bits and thereby the detailed planning of the drilling of a well can be based on the simulated optimal cost.

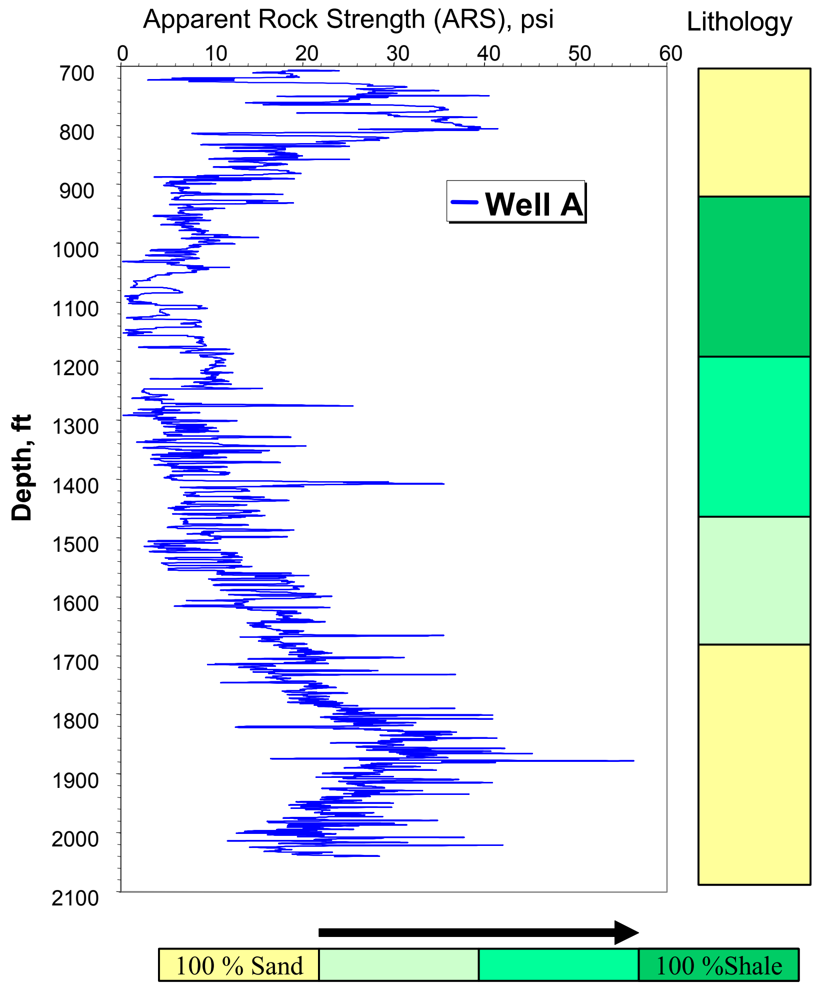


Fig. 11–Depth and lithology have a strong effect on apparent rock strength log (from DROPS® Drilling Simulator[20]).

INPUT FILES

As input files describing the operational parameters, the program requires characteristics of the bits, mud properties, and lithology information from the reference (offset) well. To keep track of the input files, all files have a header with the general information such as well name, section, size, start depth, end depth, who prepared the data, and the parameters included in the file. There are four main input files for the program[20]:

Bit file (BITFILE.bit) contains the detailed information about the drill bits that were actually used in a particular section with on in-depth description of each bit as specified below. The bit file is recognized by the **.bit* file extension. **Table 5** shows the information required for the program for each type of bit. The PDC bits and ND bits both require some geometry characteristics not commonly reflected in the bit record report.

PDC Bits: Number of blades, size, PDC layer thickness, and spatial orientation of the cutters and junk-slot area of the bit. The location of cutters and blades are shown in **Fig. 12**. PDC cutters are usually of three different sizes 19 mm (3/4-in.), 13 mm (1/2-in.) and 9 mm (3/8-in.).

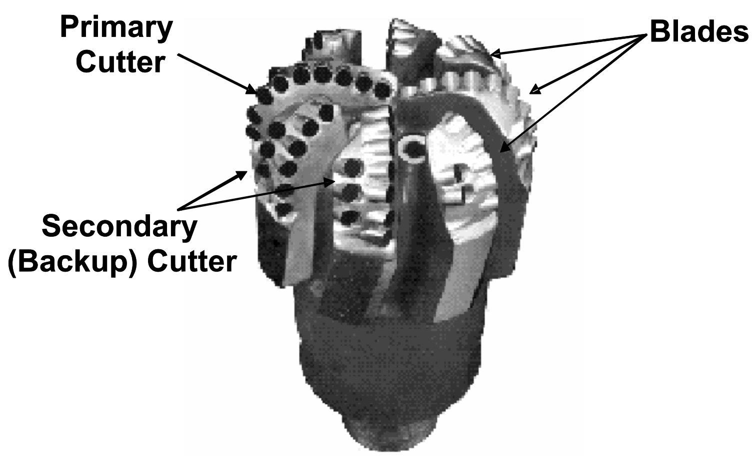


Fig. 12–Location of primary and secondary cutter in a PDC bit (from ReedHycalog[21])

The cutter's PDC-layer thickness and the junk-slot area of the bit are shown in **Fig. 13**; usually synthetic diamond disks are about 1/8-in. thick.

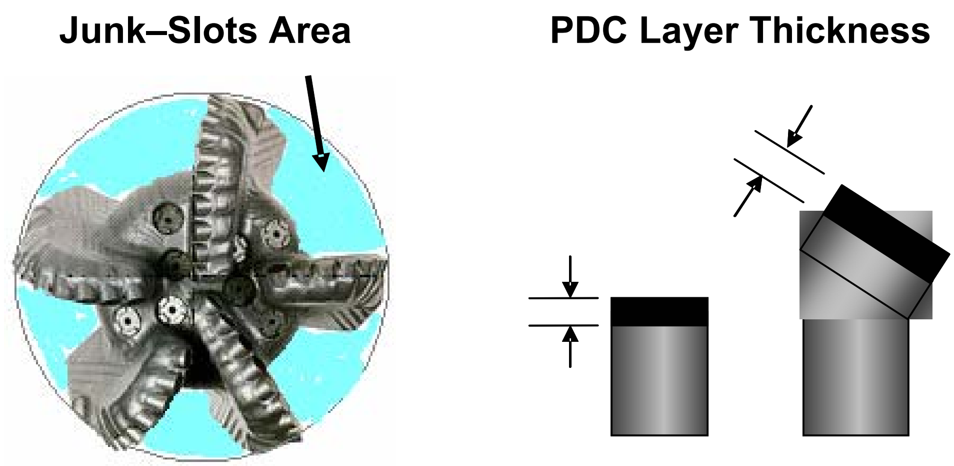


Fig. 13– PDC bit junk-slot area and PDC-layer thickness.

Other geometric characteristics required are the spatial orientations of the cutters defined by siderake angle, backrake angle, exposure, and horizontal distance between primary and backup cutters. **Fig. 14** shows the cutter orientation as a function of the exposure, and backrake and siderake angles.

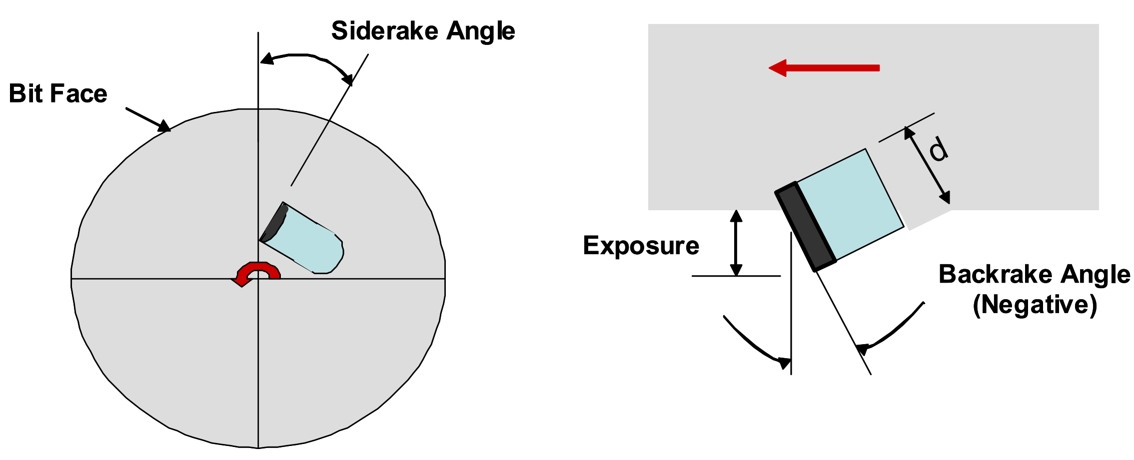


Fig. 14– PDC cutter orientation expressed in terms of exposure, backrake, and siderake (After Bourgoyne *et al.*[11]).

TABLE 5—BIT INPUT FILES PARAMETERS (DROPS® USER MANUALPARAMETERS[20])

Parameter	Unit	Explanation
[Info]		General info section
Version	N/A	File version
Well	N/A	Well name
Prepared by	N/A	Prepared by
Comment	N/A	**Optional**: Any comments, special considerations, etc.
[Bit serial no]	N/A	Manufactures bit serial
Bit Type	N/A	Bit type, PDC, TRI or NDB
IADC Code	N/A	IADC Code
Bit Diameter	Inch	Bit diameter
TVD In	Meter	True vertical start depth for bit run
TVD Out	Meter	True vertical end depth for bit run
MD In	Meter	Measured start depth for bit run
MD Out	Meter	Measured end depth for bit run
Wear In	N/A	Bit wear status before drilling as determined by IADC bit grading
Wear Out	N/A	Bit wear status after drilling as determined by IADC bit grading
Cost	US Dollars	Actual cost of drill bit
Cost DHM	US Dollars/ Day	Actual cost of motor rental per day
Manufacturer	N/A	Name of bit manufacturer
Bit Description	N/A	Bit description from manufacturer
Nozzle1..Nozzle8	1/32 Inch	**Required for TRI and PDC bits:** Description of the bits nozzle sizes, in 32's of an inch.If the bit has less than 8 nozzles, enter 0.0 in the remaining fields
Primary Number of Cutters	N/A	**Required for PDC bits:** Number of primary cutters on the bit.
Backup Number of Cutters	N/A	**Required for PDC bits:** Number of backup cutters on the bit.
Primary Cutter Size	Inch	**Required for PDC bits:** Size of primary cutters
Backup Cutter Size	Inch	**Required for PDC bits:** Size of backup cutters
Primary Backrake	Degree	**Required for PDC bits:** Backrake angle for primary cutters
Backup Backrake	Degree	**Required for PDC bits:** Backrake angle for backup cutters
Primary Siderake	Degree	**Required for PDC bits:** Siderake angle for primary cutters
Backup Siderake	Degree	**Required for PDC bits:** Siderake angle for backup cutters
Number of Blades	N/A	**Required for PDC bits:** Number of blades
Junk Slot Area	$Inch^2$	**Required for PDC bits:** Available area of bit for cuttings removal and cooling.
Thickness	1/64 Inch	**Required for PDC bits:** Thickness of the bits PDC layer.
Exposure	Inch	**Required for PDC bits:** The exposure of the PDC backup cutters
Distance	Inch	**Required for PDC bits:** The horizontal distance between the primary and backup cutters on the bit
Number of Diamonds	N/A	**Required for NDB bits:** Number of diamonds
Diamond Size	Inch	**Required for NDB bits:** Size of diamonds.
Pump Off Area	$Inch^2$	**Required for NDB bits:** Pump off area
Apparent Flow Area	$Inch^2$	**Required for NDB bits:** Apparent flow area

NDB Bits: Number and size of diamonds, pumpoff area and apparent flow area.

The sizes of the diamonds used in bits are normally described as the number of stones per carat (SPC) a weight unit where one carat is equal to 200 mg. A good estimate of diameter can be obtained assuming natural diamonds as perfect spheres with constant density of 3.52 g/cm^3, and using Eq. 25,

$$D = 0.18778 \cdot \left[\frac{1}{\text{SPC}} \right]^{\frac{1}{3}} \quad \textbf{(25)}$$

Table 6 shows different diamond sizes as a function of SPC.

TABLE 6—NATURAL DIAMOND SIZES

Diamond Size (SPC)	Diameter cm	Diameter mm	Diameter in.
1	0.477	4.770	0.188
2	0.379	3.786	0.149
3	0.331	3.307	0.130
4	0.300	3.005	0.118
5	0.279	2.789	0.110
6	0.262	2.625	0.103
7	0.249	2.493	0.098
8	0.238	2.385	0.094
9	0.229	2.293	0.090
10	0.221	2.214	0.087
12	0.208	2.083	0.082
14	0.198	1.979	0.078
16	0.189	1.893	0.075
18	0.182	1.820	0.072
20	0.176	1.757	0.069

The pumpoff area, as defined by Winters and Warren,[22] reflects the radial pressure distribution beneath the bit, which governs the magnitude of the pumpoff effect (hydraulic lift). The apparent flow area is defined to include both the flow area and any effect normally associated with the discharge coefficient for the nozzle. These values can be estimated using Eq. 26 and 27 and data from a drilloff test.

$$A_e = \frac{W_H}{\Delta p_t} = \frac{W_H}{\left(p_d - p_{ob}\right)} \qquad \textbf{(26)}$$

$$KA = \left(\frac{q^2 \rho}{12031 * \Delta p_b}\right)^{0.5} \qquad \textbf{(27)}$$

The **Fig. 15** shows a typical drilloff test used to estimate the pumpoff area.

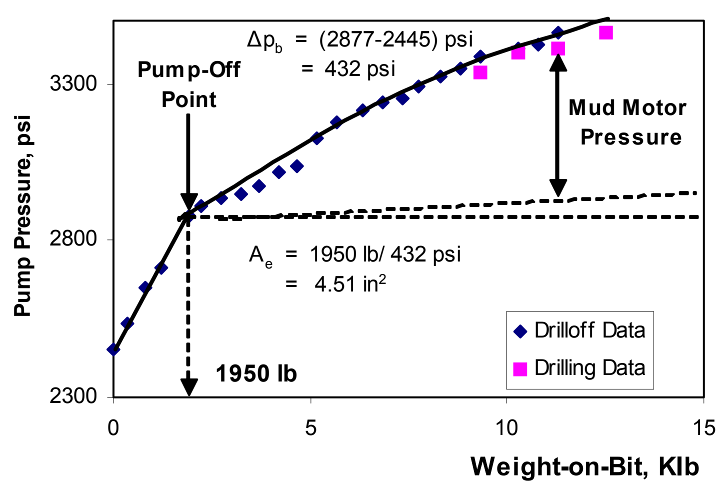


Fig. 15–Determination of pumpoff area using data from drilloff tests (after Winters and Warren[22]).

Operational data file (DRILLFILE.drill) contains all relevant operating parameters and other data for the particular section that will be used for the generation of an ARSL. The operation data file is recognized by the **.drill* file extension. **Table 7** shows the different parameter requirement and their units.

TABLE 7—OPERATIONAL DATA FILE PARAMETERS (DROPS® USER MANUAL[20])

Parameter	Unit	Explanation
MD	Meters	Measured depth
TD	Meters	True vertical depth
ROP	Meters per hour	Reported ROP
WOB	Tons	Weight on bit
RPM	Revolutions per minute	Rotary speed
GPM	Liters per minute	Flowrate
PV	Centi Poise	Plastic viscosity
MW	Specific Gravity	Mud weight
MUDTYPE	N/A	Water or oil based mud. (1 = oil, 0 = water)
DMODE	N/A	Indicates drilling mode. R = Rotary, S = Sliding and A = AutoBHA

Survey data file (SURVEYFILE.path) contains all relevant information about the directions and changes in direction (the well path) of the section for the planned well to simulate. The survey file is recognized by the **.path* file extension. **Table 8** shows the different parameter requirement and their units.

TABLE 8—SURVEY DATA FILE PARAMETERS (DROPS® USER MANUAL[20])		
Parameter	Unit	Explanation
MD	Meters	Measured depth
INCLIN	Degrees	Inclination angle
AZIMUTH	Degrees	Azimuth angle
TD	Meters	True vertical depth

Geological data file (LITHOLOGY.lith) contains all relevant information about the types of formations in the selected section. This is done by listing the percentage of occurrence of the different rock types. It is recognized by the **.lith* file extension. **Table 9** shows the different parameter requirements and their units.

TABLE 9—LITHOLOGY FILE PARAMETERS (DROPS® USER MANUAL[20])		
Parameter	Unit	Explanation
MD	Meters	Measured depth
TD	Meters	True vertical depth
SAND	N/A	Fraction of sandstone in the formation
SHALE	N/A	Fraction of shale in the formation
LIME	N/A	Fraction of limestone in the formation
DOLO	N/A	Fraction of dolomite in the formation
SILI	N/A	Fraction of silicon in the formation
CONG	N/A	Fraction of conglomerate in the formation
COAL	N/A	Fraction of coal in the formation
NULL	N/A	Not used in current version
NULL	N/A	Not used in current version
NULL	N/A	Not used in current version
P.P.	g/cm^3	Pore pressure, gradient
PERM	N/A	Permeability, (1 = permeable, 0 = impermeable)

INPUT PARAMETERS

The input parameters are specific information about a new project to be loaded into the DROPS® simulator. These parameters are divided in three groups:

General: Define the economical condition to be evaluated by the software. These basic data are user name, well name, daily rig cost, daily motor rental cost, connection time, and trip time.

Input files property sheet: Tell where the user enters or browses for input files.

Parameter Bounds*:* Define the lower-and upper-limit values of the drilling parameters to be used in the simulation.

SIMULATION

When all the input files are loaded into the program, the simulation process begins. The first step is the creation of the ARSL and its verification using the drill-behind. The result is a plot showing the lithology, ARSL, ROP, bit wear, and drilling parameters on a foot-by-foot basis (**Fig 16**).

The ROP values calculated by the software can be compared with field data and validated. Another way to validate the accuracy of the software is to compare the bit wear estimated by the program with real values. Any correction or required adjustment of the input data, such as parameters out of bounds, or improper or missing input, must be made here. Once the accuracy of the ARSL has been verified, the optimization process begins. The software offers two main ways to improve drilling performance.

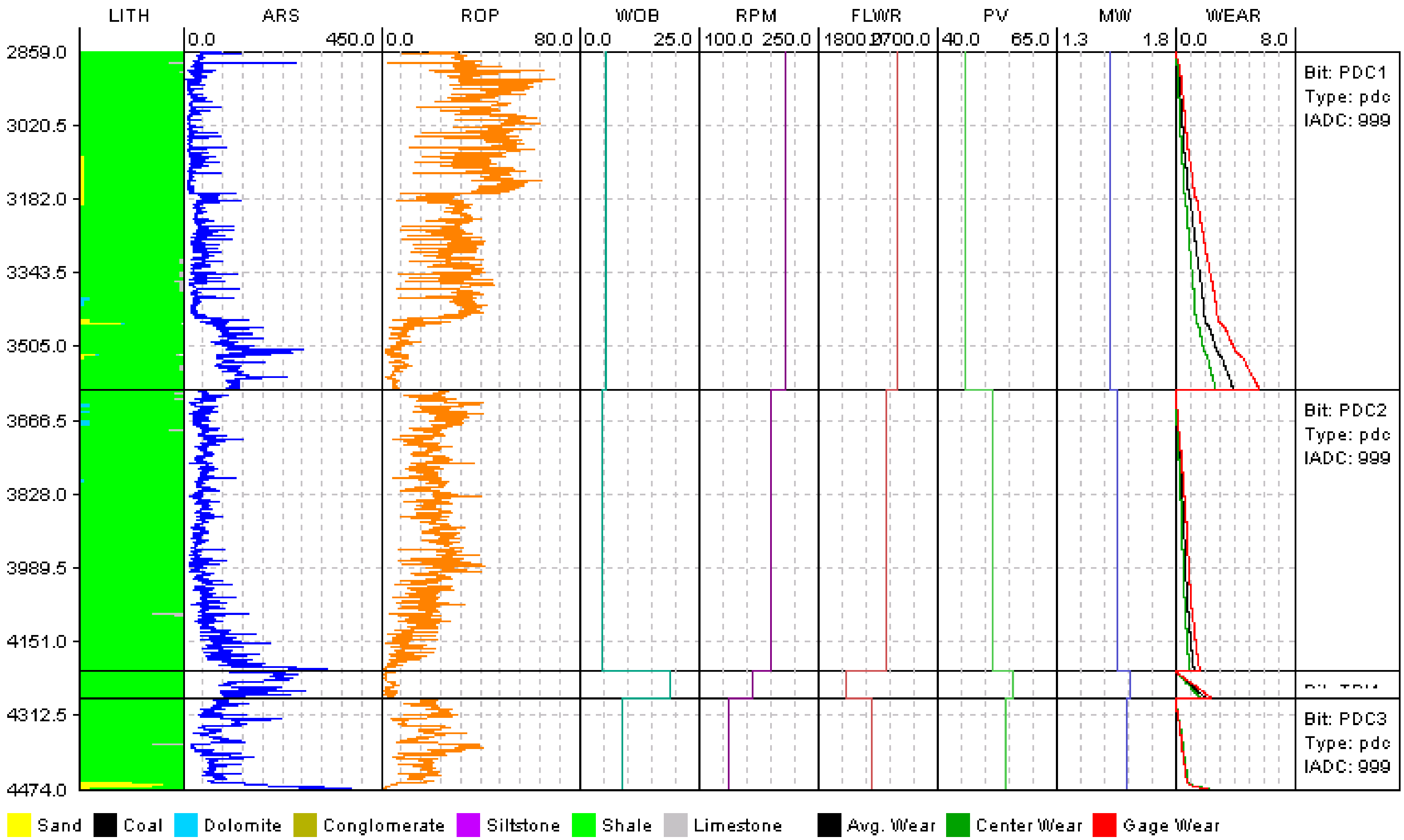


Fig. 16–Default plot from DROPS® at the beginning of the simulation (from DROPS® Drilling Simulator[20]).

Bit selection: With the ARSL defined, different bits can be evaluated by comparing their performance in ROP, wear, and cost per foot. The program allows using the same bits from the initial simulation or introducing new bits. It is possible to change the bit depth in and out as a function of the user's criteria.

Drilling parameter*:* Two separate modules work in the optimization. The Bit Hydraulics Analysis feature enables the user to input information about the bit's nozzles, flowrate, and mud weight to calculate the hydraulic horse power per square inch (HSI). The artificial intelligence (AI) module is an automatic parameter selection module that identifies the optimal combination of parameters within the specified range of WOB, RPM and specified number of sections in a bit run.[20]

The Mud Weight Program is an additional feature that gives the user an option to define a mud-weight program independently from the initial input data. The effect of mud program change on the bit performance can be accurately evaluated

Additionally, the software has other features that can be used for simulation in some specific conditions.

The follow-up module can be used to simulate or re-simulate an existing well. It is specially designed for use in a follow-up scenario, where a well has been planned and simulated, and the user needs to re-simulate or estimate bit wear. The user can recalculate ROP based on data from the field or calculate a new ARSL and compare to the original.

The Geology feature was designed to let users manually edit rock-mechanics properties for a well to be able to lengthen, shorten or otherwise change a project's geology. This is done by exporting the project's geology to a file that will contain ARSL and lithology information.

PRESENTATION OF RESULTS

The results of the simulations using DROPS® can be obtained in different ways; both numerical values and graphics are available for the user. The default plot containing the lithology, ARS, ROP, operating parameters, and bit wear is the initial result of the simulation. The control sheet shows the numerical results of the simulation for each bit and a simulation results summary showing a discrimination of time and cost per foot for every well's simulation run (**Fig. 17**).

Additionally, the numerical values of ARSL and ROP simulated for every meter can be exported to ASCII files using the file exporting capabilities.

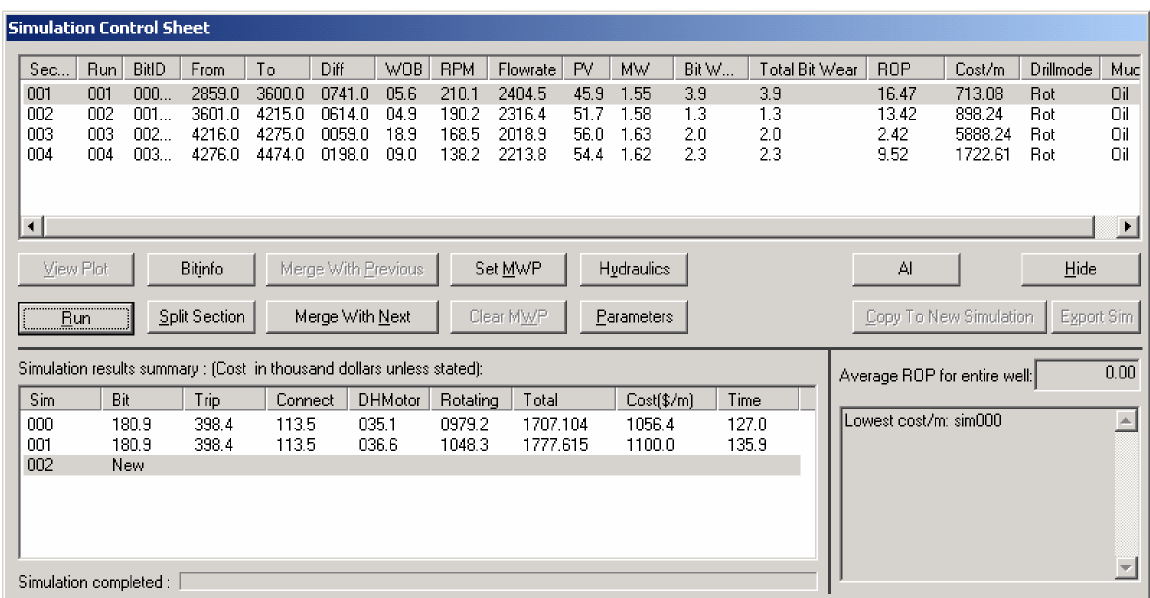


Fig. 17–Simulation control sheet shows the numerical simulation results (from DROPS® Drilling Simulator[20]).

FIELD DATA

BOSQUE FIELD

The Bosque field covers approximately 29,500 acres, located approximately 300 miles east of Caracas, in the eastern basin of Venezuela[23] **(Fig. 18)**. The Bosque field is located in the east of Furrial and Carito fields and north of Santa Barbara field, in the north of the Maturin subbasin of Maturin, eastern Venezuela.

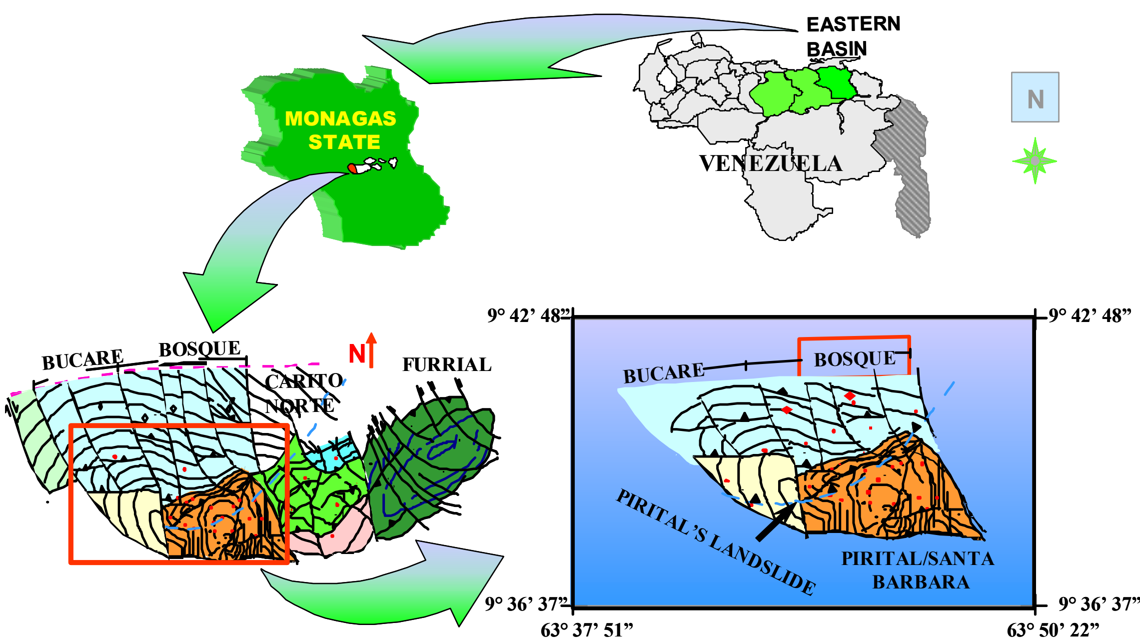


Fig. 18–Geographical location of Bosque field, Venezuela.

GEOLOGY

The crash between the Caribbean and the South America plates during the Oligocene-Miocene period created the main characteristic of the area: the existence of a great inverse fault in the north south direction called Pirital's Landslide **(Fig. 19)**. Because of this landslide, Cretaceous formations overlie Miocene formations. The section containing these Cretaceous formations is called the Aloctono block.

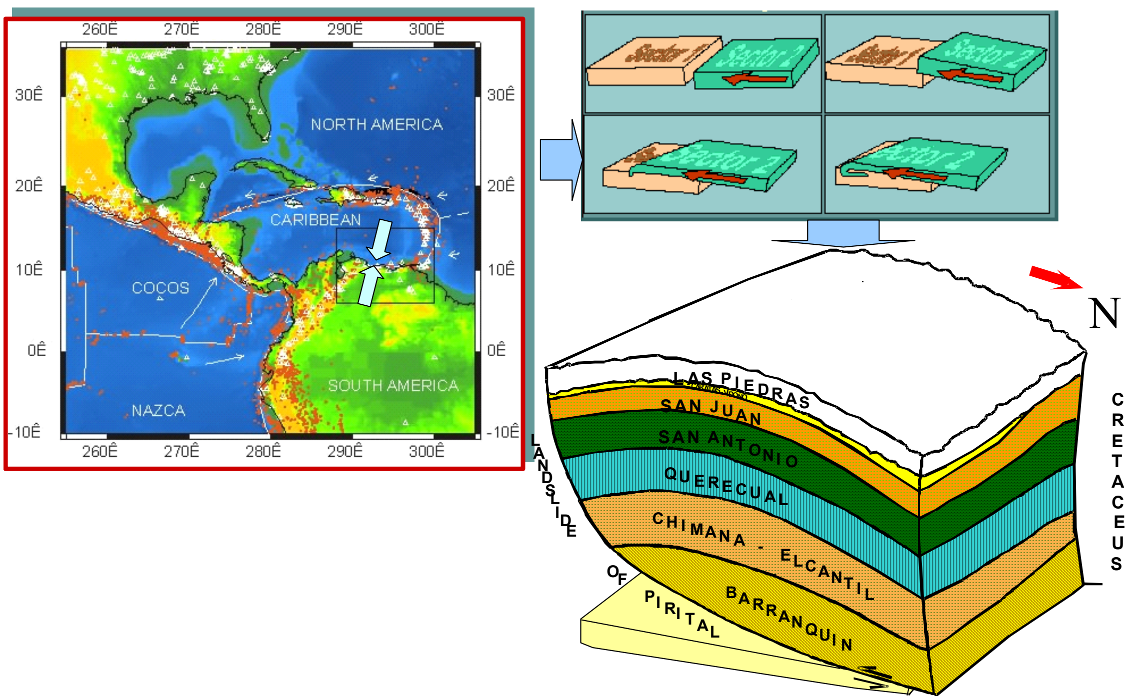


Fig. 19–Genesis of Pirital's landslide, Bosque field, Venezuela.

The stratigraphic column of the Bosque field consists of the following formations: Mesa/Las Piedras of the Upper Miocene, Morichito of the Upper Miocene, Aloctono block (San Antonio, Querecual, Chimana-El Cantil, and Barranquin) of the

Cretaceous, Carapita of the Lower Miocene, Naricual of the Oligocene and San Juan of the Cretaceous. Avila *et al.*[23] described the lithology of these formations as follows:

La Mesa / Las Piedras: Contains gray clays (soluble, plastic, and hydratable), brown shale with occasional levels of quartz sands, conglomerate sandstones, and other conglomerates.

Morichito: Consists of unconsolidated silts, such as sands and clays. Most of the sands are crystalline; grain fine-to-medium grain, cemented with calcium carbonate and silica.

San Antonio: Mainly crystalline sandstones, the grain size is small to medium, with good sphericity. The grains are very well-sorted and consolidated, generally with calcareous and siliceous cement.

Querecual: Presents alternations of gray and black shales, and small grained, well-consolidated limestones. Toward the middle part, the limestone percentage decreases, and toward the base, the maximum development of shaly layers are observed.

Chimana: The upper part is mainly shaly calcareous, interbedded with small quantities of sandy lime material. Toward the center and lower-half, the percentage of limestone decreases. Very well sorted crystalline-quartz sandstones of small and medium grain size are predominant.

El Cantil: Monotonous sequence of crystalline, gray quartz sandstones. The grains are fine to very fine, subrounded, very well-sorted, and consolidated by siliceous cement. Limestone is found in small quantities.

Barranquin: Formed by quartz crystalline sandstones of fine to medium grains, well-sorted and consolidated by siliceous cement. The basal part is constituted of green-gray shale. It is possible to find hard, brilliant coal in blocks and gray limestone.

Carapita: Consists of a monotonous sequence of shales of clear and dark gray color, hard, compacted, lightly calcareous, and carbonaceous blocks. Laminations of limestone of subrounded to rounded grains, well-sorted with calcareous cement. Crystalline quartz sandstones are present in the base.

Naricual: This is the primary hydrocarbon-producing formation. It is constituted of massive gray and/or brown sandstone with fine to medium grains, moderately sorted and sub-rounded. The predominant sedimentary structure is high-angle cross stratification. The rock matrix is cemented by silica and locally by carbonates including nodules of dolomites and pyrite.

San Juan: Constituted mainly of massive sandstone of white and gray tones, and crystalline quartz of fine to medium grain. The basal part is more calcareous, interbedded with limestones and black shales.

Because of the north-south orientation of the Pirital's landslide, the Aloctono block disappears forward to the south (Santa Barbara field) and has its biggest thickness to the north, where the Bosque field is located **(Fig. 20)**.

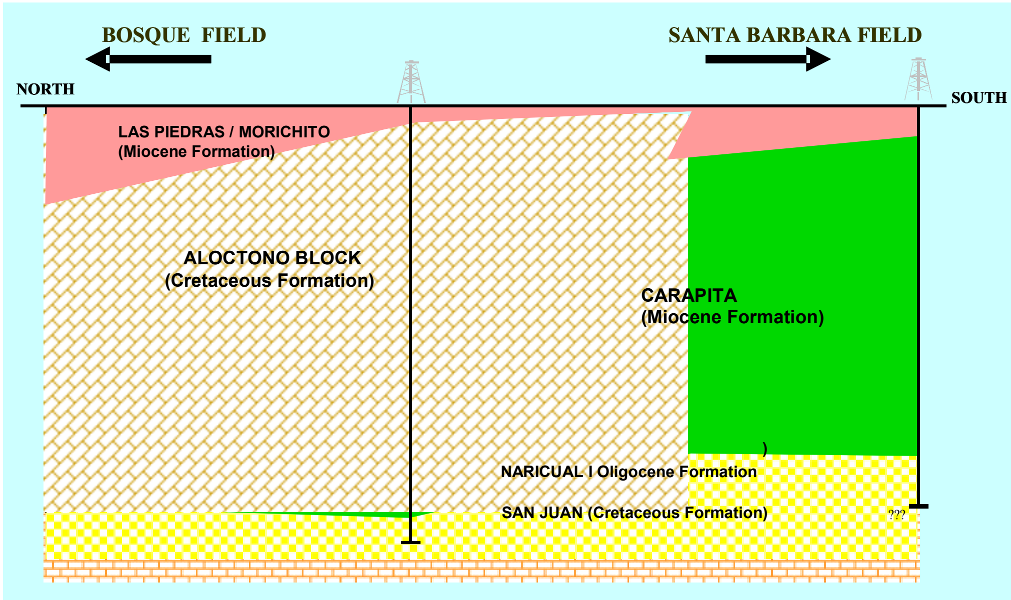


Fig. 20–Bosque field structure.

ALOCTONO BLOCK DRILLABILITY

The drilling operations in the Bosque field have a strong impact from the Aloctono block conditions: which are hard and abrasive with large dips and a faulting structure. The main drilling characteristics are:

- Low ROP.
- Wellbore instability.
- Lost-circulation problems.
- A strong tendency to trajectory deviation.

All these aspects have affected the field's profitability. Economical analysis shows that drilling the Aloctono block represents nearly 50% of the total cost and 53% of the total time of the well construction.[23] Any improvement in the drilling performance will have a strong positive impact on the economic yardsticks of the field.

WELL LOCATION

For the evaluation of the DROPS® software using field data, a well in the Aloctono block was selected.

The DL-1 well is located in the northeast of the Santa Barbara field, in the Bosque field, eastern Venezuela **(Fig. 21)**.

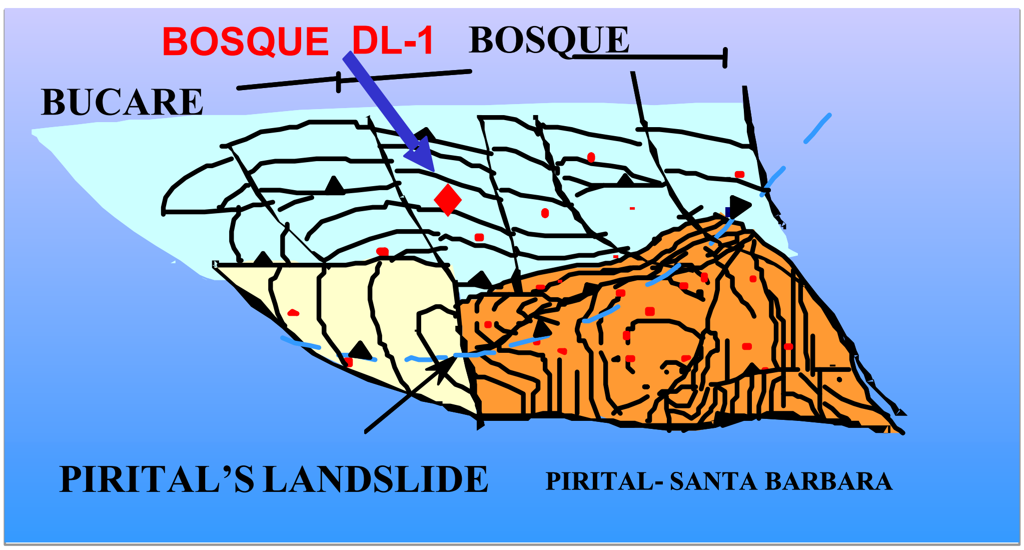


Fig. 21–Location of Well DL-1 in the Bosque field.

WELL DESIGN

The DL-1 well was drilled to the total depth of 21,192 ft. The casing design required five sections to reach the reservoir:

- 20-in. casing @ 1,000 ft. This casing section covered the low pressure, unconsolidated formation of La Mesa/Las Piedras.
- 13-3/8-in. casing @ 6,100 ft. This casing allowed isolation of the younger Morichito formation from the Aloctono block and guaranteed enough formation integrity to continuing drilling.
- 9-5/8-in. casing @ 17,583 ft. This casing isolated low-pressure formations of Aloctono block from the high pressure Carapita formation.
- 7-5/8-in. liner @ 18,880 ft. The liner isolated the Naricual production zone, reducing the differential pressure in the following section.
- 5-½-in. liner @ 21,192 ft. This liner covered the last part of the well and isolated the San Juan formation (Cretaceous) from the Naricual formation.

SECTION FOR ANALYSIS

To verify the accuracy of the software, a section of the well was selected to be evaluated. The objectives were:

- Evaluate the capacity of the software to reproduce the performance observed in the well. In this step the simulator was tuned to match the well response.
- Generate simulations using different drilling parameters and bits. This step optimized the drilling operation by reducing the cost of the section.

In the selection of the section to evaluate, the following criteria were used:

- Availability of the data. The drilling parameters, mud properties, pore pressure, lithology, and bit characteristics were considered critical data.
- Impact of the cost optimization on the well profitability. We looked for the section with the strongest impact on time and cost.
- Field and/or regional interest in the optimization of the drilling performance in the evaluated formation.

For the DL-1 well, the 12-¼-in. section accomplished all criteria. The drilling parameters, bit properties, and a good interpolation of pore pressure were available foot-by-foot. The types of bits used were predominantly three-cone with insert tooth and some PDC bit. The lithology was available every 20 ft, which allowed good formation characterization.

The 12-¼-in. section represented approximately 50% of the total cost and 53% of the total time of well construction.

Because the Aloctono block is present in all of Bosque Field, some areas of the Santa Barbara field, and it is considered to extend to other fields like Macal and Bucare, its drilling optimization is considered critical. The economical viability of these fields requires a strong improvement of the drilling operations in the Aloctono block, with a consistent reduction of time and cost.

PORE PRESSURE

The pore pressure of the section was defined from data from offset wells, the mud logging unit, and repeat formation tester logs run in the DL-1 well.

The pore pressure values for each formation in the Aloctono block show a tendency for normal to subnormal pore pressure. This is coherent with the geology of the area, where faulted structures and outcrops allow free communication of fluids between different formations and the surface.

In addition this behavior was confirmed during drilling operation of the wells delineator 1 and 2 located in two different areas of Aloctono block.

Table 10 shows pore pressure, formations and a qualitative evaluation of the permeability of the section.

TABLE 10—PORE PRESSURE AND PERMEABILITY OF THE 12-1/4-IN. SECTION OF THE WELL DL-1

Depth	Pore Pressure			Permeability	Formation
m	ppg	gr/cm^3	psi	(Y/N)	Name
1859.8	8.33	1.00	2,642	N	San Antonio
2012.2	8.33	1.00	2,859	N	San Antonio
2042.7	9.62	1.15	3,352	N	San Antonio
2134.1	9.07	1.09	3,301	N	San Antonio
2164.6	7.59	0.91	2,802	N	San Antonio
2318.9	8.33	1.00	3,292	Y	San Antonio
2423.8	7.96	0.96	3,291	Y	Querecual
2591.5	8.00	0.96	3,536	Y	Querecual
2667.7	8.14	0.98	3,704	Y	Querecual
2701.2	8.14	0.98	3,750	Y	Querecual
3237.8	8.14	0.98	4,495	Y	Chimana Cantil
3292.7	8.14	0.98	4,571	Y	Chimana Cantil
3353.7	8.14	0.98	4,656	Y	Chimana Cantil
3414.6	8.14	0.98	4,741	Y	Chimana Cantil
3482.6	8.14	0.98	4,834	Y	Chimana Cantil
3536.6	8.14	0.98	4,910	Y	Barraquin
3780.5	8.14	0.98	5,249	Y	Barraquin
3811.0	8.14	0.98	5,291	Y	Barraquin
3963.4	8.14	0.98	5,503	Y	Barraquin
4146.3	8.14	0.98	5,757	Y	Barraquin
4207.3	8.14	0.98	5,841	Y	Barraquin
4268.3	8.14	0.98	5,926	Y	Barraquin
4420.7	8.14	0.98	6,138	Y	Barraquin
4573.2	8.14	0.98	6,349	Y	Barraquin
4725.6	8.14	0.98	6,561	Y	Barraquin
4878.0	8.14	0.98	6,772	Y	Barraquin
5051.8	8.14	0.98	6,984	Y	Barraquin
5182.9	8.14	0.98	7,196	Y	Barraquin
5243.9	8.14	0.98	7,280	Y	Barraquin
5304.9	8.14	0.98	7,365	Y	Barraquin
5335.4	8.14	0.98	7,407	Y	Barraquin

DRILLING PARAMETER

The drilling parameters were obtained from the mud-log unit. The parameters record was made foot by foot during the entire drilling operation.

The following parameters were considered critical:

- Measured depth (MD) of the well, taken from the length of the drillstring. For the 12-¼-in. MD and true vertical depth (TVD) were considered the same because of the low deviation observed in this section of the well.
- Weight on bit (WOB), the total weight applied on the bit to drill.
- Rate of penetration (ROP), the velocity of penetration of the bit into the formation.
- Revolution per minutes (RPM), the velocity of rotation of the bit.
- Gallons per minute (GPM), flow rate of drilling fluid.

DRILLING MUD PROPERTIES

The drilling fluid used in the 12-¼-in. was 100% mineral oil mud. A drilling fluid is called oil mud if the continuous phase is composed of a liquid hydrocarbon.[11] In the case of a 100% mineral oil mud, the liquid hydrocarbon has low toxicity; the dispersed phase, normally water, has low concentration; and no primary emulsifier is used.

The 100% oil mud is characterized by superior lubrication characteristics, more inhibition than inhibitive water mud, mud densities as low as 7.5 lbm/gal, and good rheological properties. **Table 11** shows the typical properties of the mud used during the drilling of Aloctono.

TABLE 11—DRILLING MUD PROPERTIES OF 12-¼-IN. SECTION OF THE WELL DL-1.

Depth ft	Density ppg	Funnel Viscosity sec/qt	Plastic Viscosity cp	Yield Point lb/100 ft^2	Filtrate HTHP cm^3/30 min
6151	8.5	35	6	4	9
6352	8.8	47	36	12	7.4
6612	8.6	46	12	8	7.8
8457	8.5	54	12	10	7.8
8830	8.6	50	11	12	7.8
14708	8.7	63	16	11	6
15597	8.8	67	19	12	6
15866	8.9	59	18	11	6
16463	9	54	16	12	6
16504	9.1	54	16	12	6
17278	9.2	69	20	12	5.6
17501	9.3	69	20	12	5.6
17511	9.4	75	23	11	5
17532	9.5	76	23	12	5
17583	9.5	76	23	12	5

BIT RECORD

The length and drillability of the section required a total of 32 bits. Three different types of bits were run in the well: Roller Cutter Bits (RCB), polycrystalline diamond bits (PDC), and Natural Diamond Bits (NDB).

The entire bit program was run with similar hydraulic parameters, including number of nozzles and flow rate. **Table 12** shows the bit record of the well, including International Association of Drilling Contractor (IADC) classification and wear evaluation.

TABLE 12—BIT RECORD OF 12-1/4-IN. SECTION OF THE WELL DL-1

				DEPTH IN		DEPTH OUT		ROP		
Nº	MODEL	MAKER	IADC	ft	m	ft	m	ft/h	m/h	WEAR EVALUATION
1	10M	SMITH	435	6150	1875.0	6584	2007.3	10.53	3.21	1-1-No-A-E-1-No-PR
2	15M	SMITH	445	6584	2007.3	7467	2276.5	10.40	3.17	2-3-WT-A-E-0-BT-PR
3	10M	SMITH	435	7467	2276.5	8790	2679.9	14.91	4.55	8-8-LC-#3-F-?-X-PR
4	EHP43HCA	SMITH	437	8792	2680.5	8824	2690.2	4.62	1.41	4-4-BT-M-E-0-WO-PP
5	10M	SMITH	435	8830	2692.1	8944	2726.8	10.52	3.21	1-1-BT-M-E-0-WO-PP
6	15M	SMITH	445	8944	2726.8	9300	2835.4	11.15	3.40	2-0-WT-M-EEE-0-TQ
7	15MFD	SMITH	447	9300	2835.4	9870	3009.1	8.44	2.57	1-0-WT-A-E-0-No-TQ
8	15MFD	SMITH	447	9870	3009.1	10058	3066.5	10.65	3.25	2-0-WT-A-E-0-WO-PP
9	FM1941L	DBS	999	10058	3066.5	10288	3136.6	5.67	1.73	3-4-WT-A-x-0-CT-TQ
10	EHP43HKPRC	REED	437	10288	3136.6	10618	3237.2	6.00	1.83	7-7-BT-A-F-2-WT-TQ
11	EHP44HKPRC	REED	447	10618	3237.2	10770	3283.5	5.62	1.71	3-6-CI-M-F-3-No-TQ
12	15 MFDP	SMITH	447	10770	3283.5	11176	3407.3	6.90	2.10	3-4-WT-A-E-0-No-TQ
13	15 MF	SMITH	447	11176	3407.3	11528	3514.6	5.74	1.75	3-6-WT-A-E-0-GR-PR
14	15 MF	SMITH	447	11528	3514.6	12025	3666.2	7.59	2.31	4-2-WT-A-E-0-No-HR
15	15MF	SMITH	447	12025	3666.2	12492	3808.5	8.09	2.47	4-6-WT-A-E-1-BT-PR
16	15MFPD	SMITH	447	12492	3808.5	12891	3930.2	6.96	2.12	5-7-WT-A-E-0-BT-TQ
17	20MD	SMITH	515	12891	3930.2	13223	4031.4	5.58	1.70	3-3-WT-A-E-0-BT-PR/HR
18	20MFOD	SMITH	517	13223	4031.4	13637	4157.6	6.89	2.10	4-5-WT-A-E-0-BT-HR
19	20MFODL	SMITH	517	13637	4157.6	14046	4282.3	6.60	2.01	4-4-WT-A-E-0-BT-HR
20	20MFWL	SMITH	517	14046	4282.3	14276	4352.4	9.11	2.78	3-7-WT-G-E-0-No-PR
21	MAX20G	HUGHES	517	14276	4352.4	14583	4446.0	5.98	1.82	4-7-BT-G-E-0-WT-HR
22	20MFD	SMITH	517	14583	4446.0	14863	4531.4	5.47	1.67	4-2-WT-A-E-0-OC-PR
23	TI2352	DBS	911	14863	4531.4	15629	4764.9	5.34	1.63	8-6-RO-C-X-0-WT-PR
24	20 MFDP	SMITH	517	15629	4764.9	15866	4837.2	7.54	2.30	3-2-WT-A-E-0-BT-TQ
25	20 MFDP	HYCALOG	517	15866	4837.2	16234	4949.4	6.52	1.99	3-5-WT-A-E-0-BT-TQ
26	20MFODL	HYCALOG	517	16234	4949.4	16504	5031.7	4.20	1.28	3-5-WT-A-E-0-BT-TQ
27	20MFODL	SMITH	517	16504	5031.7	16655	5077.7	4.11	1.25	2-6-WT-A-E-0-BT-PR
28	20MFODL	SMITH	517	16655	5077.7	16832	5131.7	3.82	1.17	3-6-WT-A-E-0-BT-PR
29	20MFODL	SMITH	517	16832	5131.7	17057	5200.3	4.64	1.42	2-5-WT-A-E-0-BT-HR
30	20MYL	SMITH	515	17057	5200.3	17302	5275.0	5.07	1.55	3-7-WT-A-E-0-BT-HR
31	20MYL	SMITH	515	17302	5275.0	17511	5338.7	5.12	1.56	2-8-WT-A-E-0-BT-TQ
32	20MYL	SMITH	515	17511	5338.7	17583	5360.7	4.16	1.27	1-1-No-A-E-0-WT-Log

LITHOLOGY

The lithology found in the section of 12-¼-in. of the DL-1 well, Aloctono block, is characterized by alternate massive sandstones and shales interbedded with an abundance of dolomite and limestone. Four different formations were drilled in the section **(Fig. 22)**.

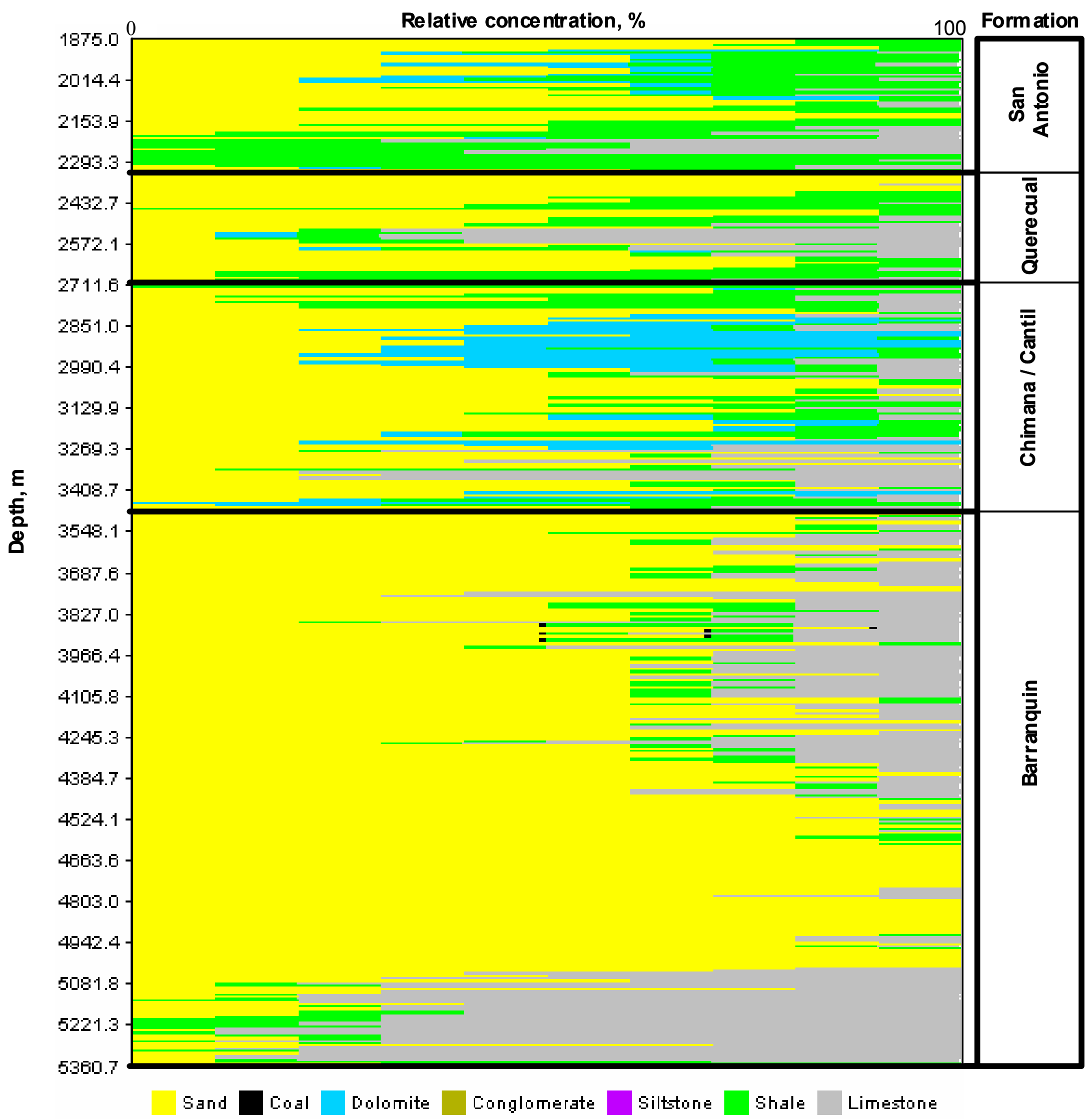


Fig. 22- Lithology and formations drilled in the 12-¼-in. section of the Well DL-1.

INPUT PARAMETERS

The values of the general input parameters used in this research are shown in **Table 13**. They are based on economics and conditions typical of Eastern Venezuela, using a 3,000 hp land drilling rig with a top drive unit.

TABLE 13—INPUT PARAMETER FOR THE 12-1/4-IN. SECTION OF WELL DL-1

Parameter	Value
Well name	DL-1
Daily rig cost	20,000 $
Daily mud motor / MWD cost	10,000 $
Connection time	1.3 min
Trip time for 1,000 ft	45 min

The parameter bounds shown in the **Table 14** were selected after taking into consideration the minimum bit requirements, equipment limitations and drilling mud conditions.

TABLE 14—PARAMETER BOUNDS FOR THE 12-1/4-IN. SECTION OF WELL DL-1

Parameter	Bound	
	Lower	Upper
Weigt on bit, Tons	3	25
Rotary speed, rpm	70	1000
Flow rate, lpm	3500	2000
Mud weight, sg	1.1	1.2
Rate of penetration, m/h	0	100

SIMULATION RESULTS

ARSL CREATION AND VALIDATION

Once all the input files and startup parameters were introduced in the DROPS® simulator, the simulation process started with the creation of the ARSL log and its verification with the Drill-behind evaluation. **Fig. 23** shows the initial simulation results.

The default plot shows a simulation of the original drilling performance for the 12-1/4-in. section Well DL-1.

The first track contains the lithology of the section.

The second track shows ARSL calculated by the program using the lithology, drilling parameters (tracks four to nine) and bit information.

The third track contains the ROP predicted by the simulator using the original drilling parameters, bits and the ARSL calculated. We observe a strong correlation between the ARSL and the ROP trend: high ARSL mean lower values of ROP, low ARSL mean high values of ROP.

The tenth track contains an estimate of wear for each bit. The plot shows three different curves, the red one represents the bit gage wear, the green one the center wear and the black one the average wear for the bit.

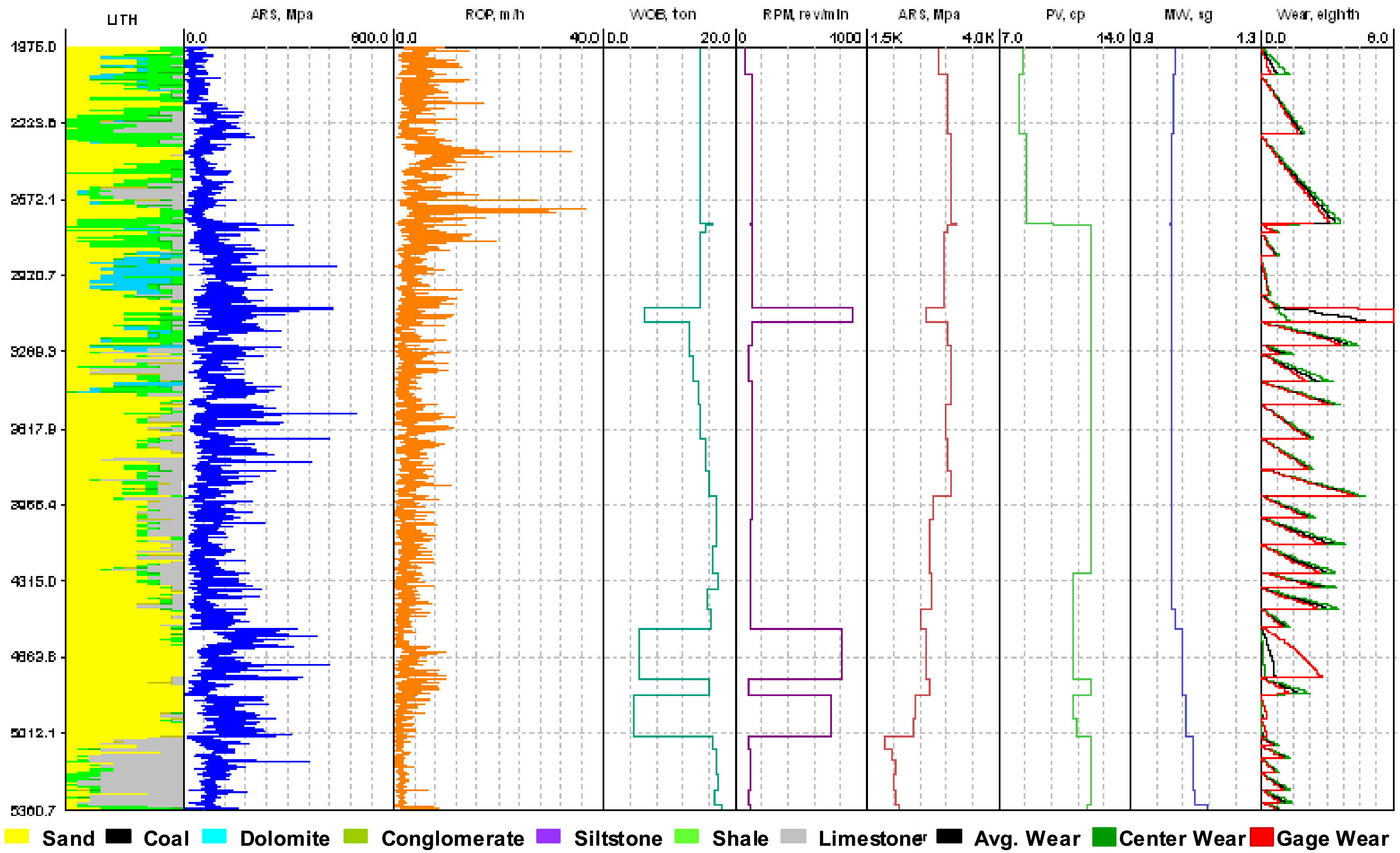


Fig. 23-Initial simulation result for the 12-¼-in. section, Well DL-1.

After the base simulation (Sim-000) was run, comparison between the actual (real) and simulated ROPs were made on a meter-by-meter basis for every formation drilled in the section. The results (**Figs. 24, 25, and 26**) show that ROPs have similar trends, with a difference of ROP average less than 5% (**Table 15**).

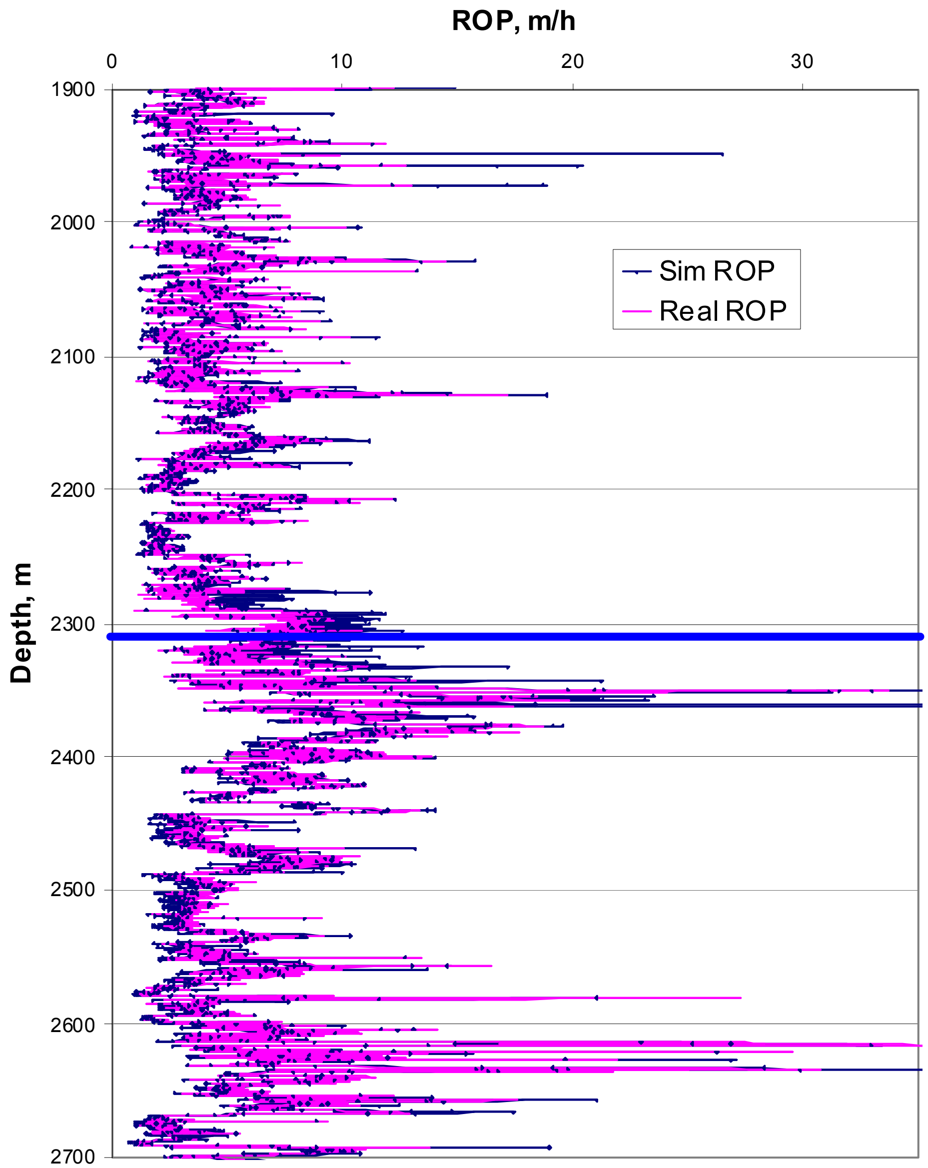


Fig. 24-Comparison between simulated and real ROPs shows a close match in the San Antonio/Querecual formations, Well DL-1.

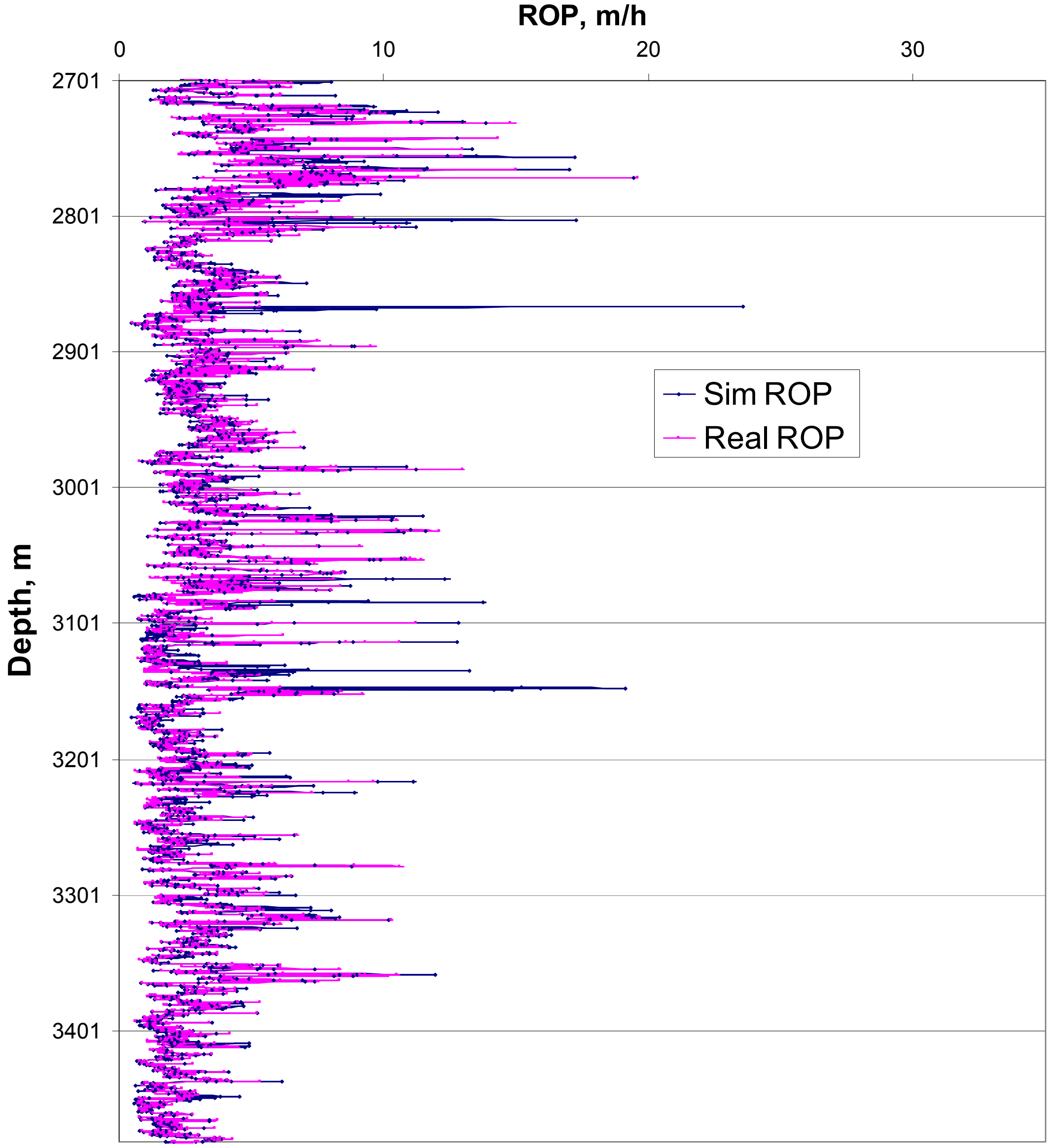


Fig. 25-Comparison between simulated and real ROPs shows a close match in the Chimana/El Cantil formations, Well DL-1.

Fig. 26-Comparison between simulated and real ROPs shows a close match in the Barranquin formation, Well DL-1.

TABLE 15—REAL AND SIMULATED ROP IN THE 12-1/4-IN. SECTION OF WELL DL-1

Formation	Average ROP Real m/h	Average ROP Simulated m/h	Deviation %
San Antonio	4.4	4.6	5.6
Querecual	6.6	6.7	1.7
Chimana-El Cantil	3.2	3.4	5.0
Barranquin	2.5	2.6	2.3
All the sections	3.3	3.4	3.6

A second verification of the accuracy of the DROPS® was performed using the available electric openhole logs. Sonic and lithologic (GR) logs were run in the 12-¼-in. section. Using this information, the unconfined rock strength log was generated for the section using standard electric log methods.

A comparison of ARSL from the electric logs and generated by DROPS® is shown in **Fig. 27**. Both of them show a remarkable resemblance, with the exception of the last 300 m, where the values of ARSL from electric logs are higher than the values generated by DROPS®.

The close resemblance of simulated and real ROPs and ARSLs from electric logs and DROPS® demonstrated the accuracy of the simulator.

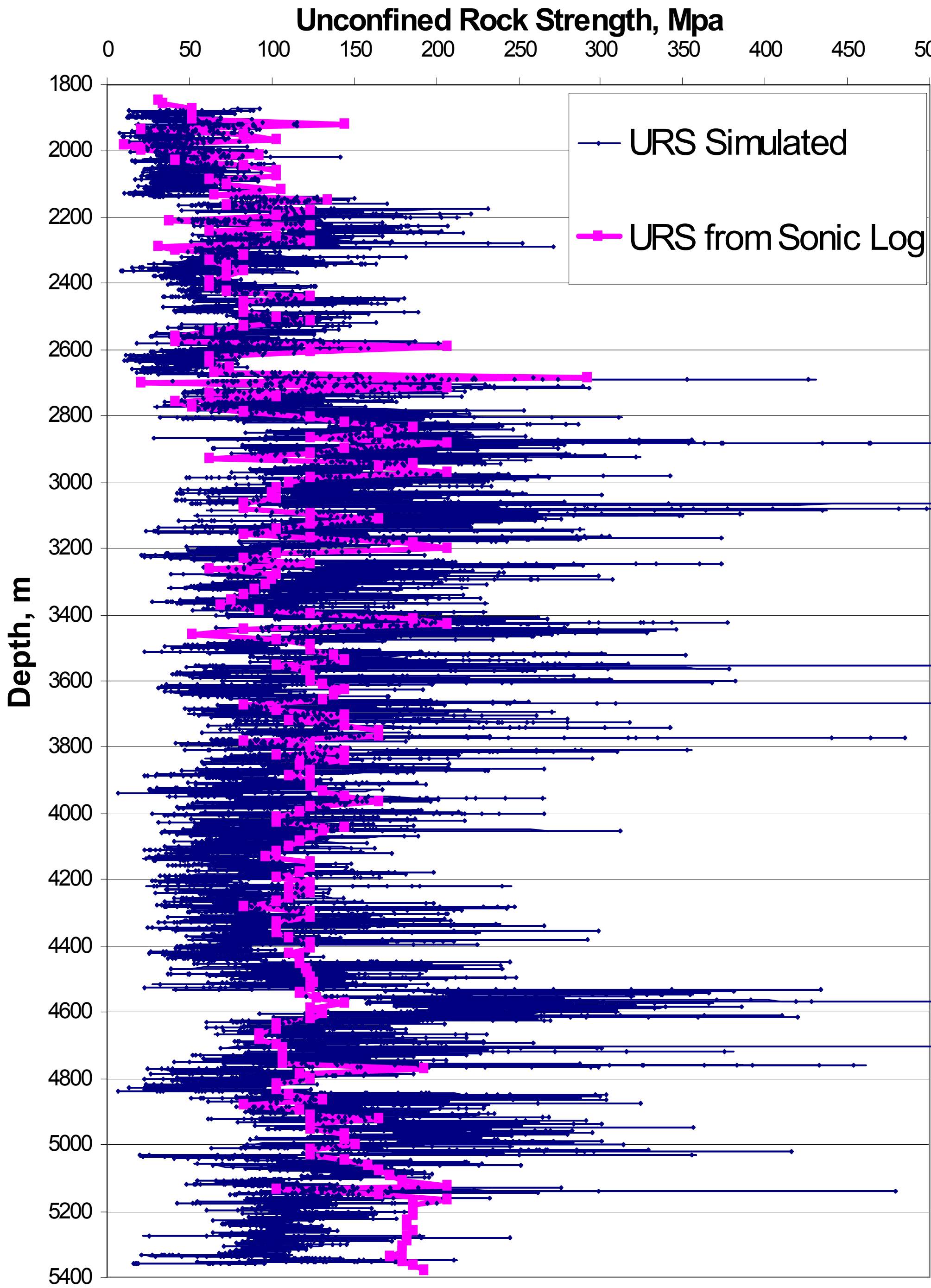


Fig. 27-Comparison between unconfined rock strength simulated and estimated from electric logs shows a similar tendency in the 12-¼-in. section Well DL-1.

OPTIMIZATION

Once the software's accuracy had been verified through the ARSL and ROP prediction process, the optimization of the drilling performance could be done. Based on the capacity of the software, the test incorporated the mud program, bit selection, and drilling parameters optimization.

Mud Program Optimization

The initial simulation was conducted using the same bits that were used in the well, with the same run intervals and operating conditions. In the following simulations, the only change was the mud-weight program. Starting from the original mud-weight program, the mud weight was reduced until the section was drilled in balance. Simulation 0 has the initial condition used in the well. Simulations 1 through 6 used a 1.10, 1.08, 1.06, 1.04, 1.02 and 1.0 gr/cm^3 as mud weight values for the entire section. Simulation 7 through 10 used a combination of different mud weights, increasing as the well got deeper (**Fig. 28 and Table 16**).

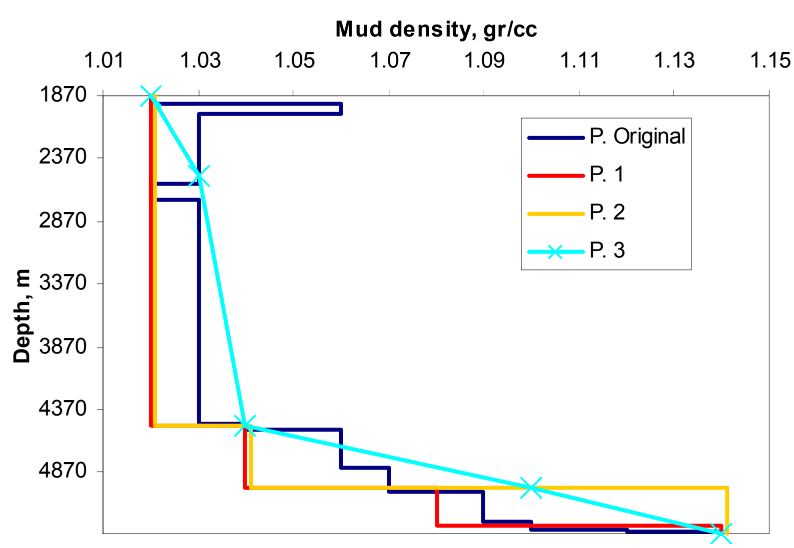


Fig. 28-Different mud-weight programs evaluated with the simulator.

TABLE 16—EVALUATION OF THE MUD WEIGHT IMPACT ON THE DRILLING OF THE PERFORMANCE 12-1/4-IN. SECTION OF WELL DL-1				
Simulation N	Mud Weight	Cost	Total time	
	g/cm^3	\$/m	hr	days
0	Original	1593.5	1570.1	65.4
1	1.14	2615.1	2582.0	107.6
2	1.10	2176.8	2165.0	90.2
3	1.08	1878.4	1936.5	80.7
4	1.06	1675.5	1734.2	72.3
5	1.04	1489.1	1528.8	63.7
6	1.02	1318.2	1351.0	56.3
7	1.00	1304.2	1340.7	55.9
8	Program 1	1469.0	1483.0	61.8
9	Program 2	1511.9	1549.2	64.6
10	Program 3	1784.5	1734.2	72.3

Fig. 29 shows a comparison between different simulations, where the best cost and time is reached when the mud weight is equal to the pore pressure (Sim-7), which means drilling was in balance. With the base criteria of a minimal safety margin of 100 psi, borehole stability, and the best cost per foot and time, Simulation 8 was considered optimal. Using this mud program, we can reduce the cost per meter by \$124 /m and the total time by 3.6 days. These values represent a reduction of 7.8% of the cost and 5.5% in time. The Mud Weight Program 1 was considered the best and used as base for rest of the optimization process.

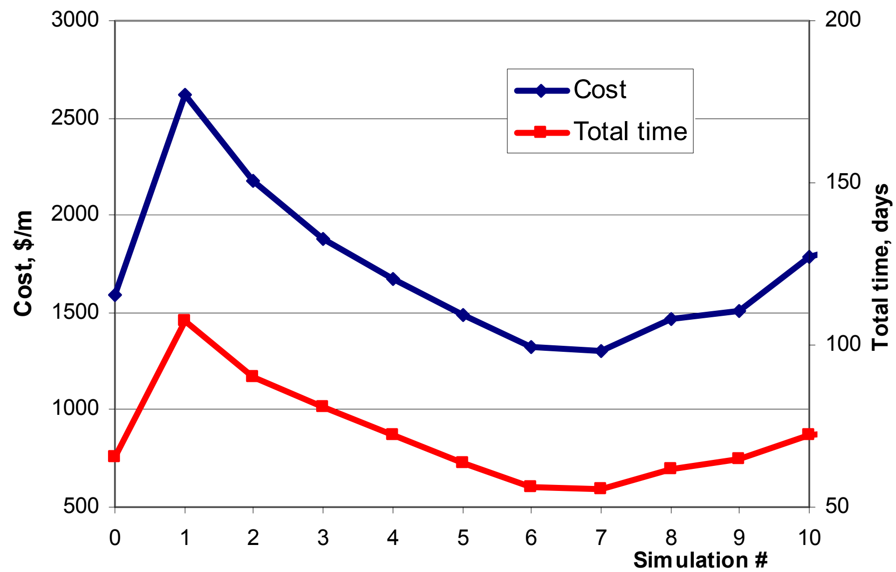


Fig. 29-Cost per meter and total time as a function of mud weight program used in the simulation.

Bit Selection Optimization

The bit selection optimization was based on the evaluation of use of drag bits and the best selection of the IADC code of the three-cone bits used in the well. The method of comparison was total cost per meter of the section and total time.

<u>Evaluation of Drag Bit</u>

Data available from the ARSL show that the first 800 m of the section (San Antonio and Querecual formations) have the lowest values of unconfined rock strength; additionally the lithology shows a large concentration of shales. These conditions are favorable for use of PDC bits. One of the advantages of this kind of bit is the absence of rotating elements, which increases the safety of the drilling operation by eliminating the risk of lost elements in the hole.

Two different models of PDC bits were evaluated. **Fig. 30** shows a comparison between a simulation using three-cone bits and another using the PDC bit with the best performance in the simulator.

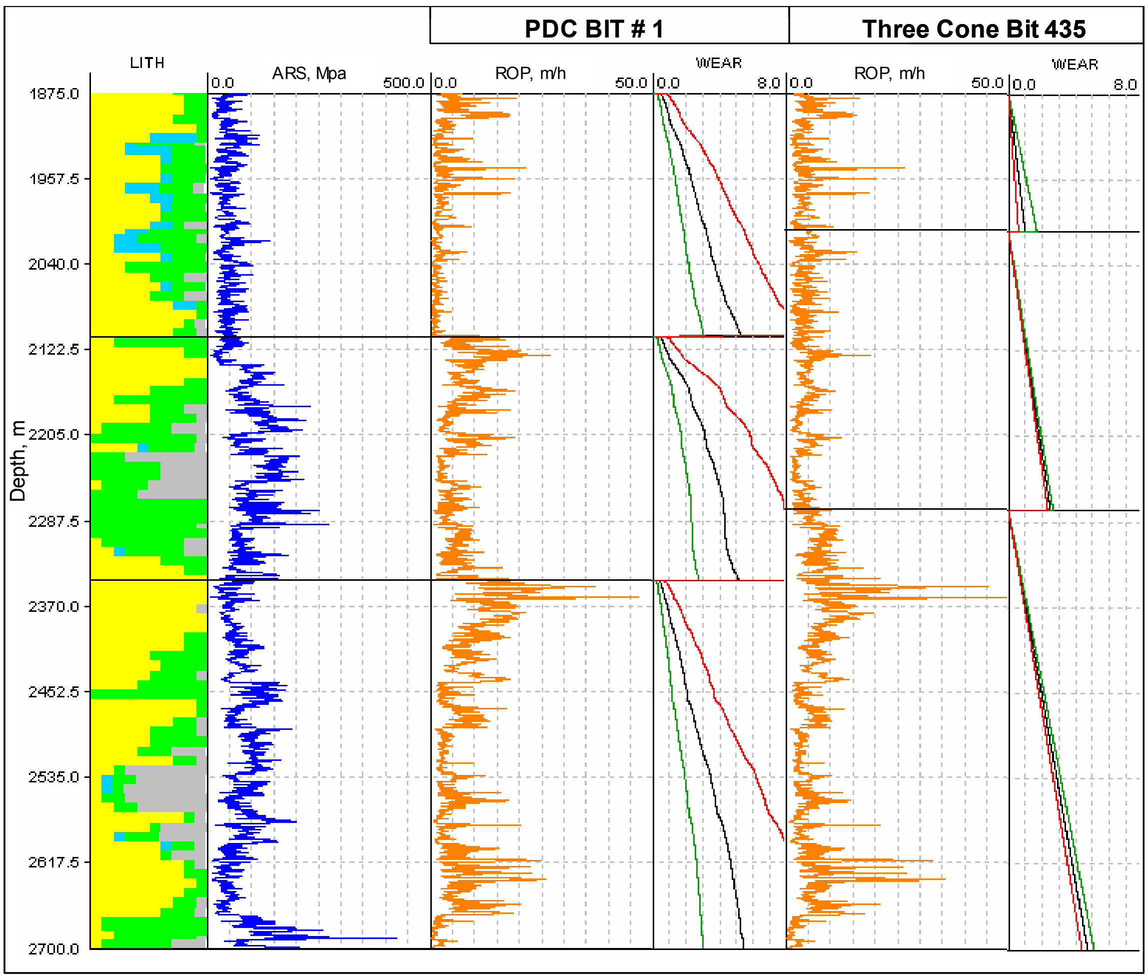


Fig. 30-Comparasion of ROP performance between PDC and three-cone bits in San Antonio/Querecual formations shows similar ROP trends.

The plot shows for the same interval, the drilling performance of three PDC and the original three-cone bits run used in the section. For the PDC bit simulation a average wear of five and one half eighths was considered as maximum tolerable (criterion for pulling out the bit).

The ROPs averages for the interval on the two simulations are similar but the average bit wear for three-cone bits is lower than the PDC. The simulations show cost per meter of each PDC run is near 10 times higher than for each three-cone bit. **Table 17** shows the numerical values for each bit run in the simulator.

TABLE 17—EVALUATION OF PDC AND THREE-CONE BIT PERFORMANCE

		San Antonio/Querecual formations			Section 12 1/4in.	
Bit Type	Run	Distance	ROP	Cost per meter	ROP	Cost per meter
		m	m/h	$/m	m/h	$/m
PDC	1	235.0	1.5	6290.0	2.2	2112.3
	2	235.0	4.5	2252.0		
	3	383.0	2.7	3440.0		
Three Cone 435	1	132.0	3.4	413.0	2.3	1240.6
	2	269.0	3.3	345.0		
	3	450.0	3.3	315.0		

The values of cost per meter and ROP from the simulations indicate that PDC bits are not the best option for this kind of formation.

Optimization of IADC Code of Three Cone Bits

The optimization of the three-cone bit was made by evaluating the performances of the bit used in the well and the operational conditions. The possibility of improving the general performance using the previous and following IADC code of bits run in the well was evaluated. Some criteria were defined previous to the simulation:

Use of three-cone bits: Costs per meter of PDC and ND bits were too high.

Limited rotational time: To prevent a bearing seal failure and the possibility of loss of a cone in the hole, the rotational times of bits in the bottomhole were limited to preset times. These values were selected taking into consideration the bit maker's recommendation and field experience. **Table 18** shows the values defined for each formation drilled in the section.

TABLE 18—ROTATIONAL TIME ALLOWED FOR THREE CONE BIT IN ALOCTONO BLOCK, 12-1/4-IN. DIAMETER

Formation		Maximum Rotating Time (h)
San Antoinio		90
Querecual		80
Chimana-El Cantil		70
Barranquin	Superior	65
	Inferior	50

Bits to be evaluated used the best seal available and special gage protection: The formations to be drilled are abrasive and initial simulations show a possible gauge problem resulting from extensive wear of the external teeth rows and gauge protection of the bits.

Fig. 31 shows the results of the different simulations, with a clear tendency to reduce cost and time as new simulations with a better bit selection were made. Again, the use of drag bits, like PDC and impregnated bits is not the best option. These bits drill further than three-cone bits, but the cost per meter is too high.

The new bit program for the section reduces the cost per meter by 66.4%, the total time by 26.1% and the increase in average ROP by 35.3% compared with the original well performance. The total number of bits to use is reduced from 32 in the original well to only 20 in the optimized simulation. All of this means a reduction of drilling cost of approximately US. $ 2.8 million and a reduction of 16 days in the total drilling time.

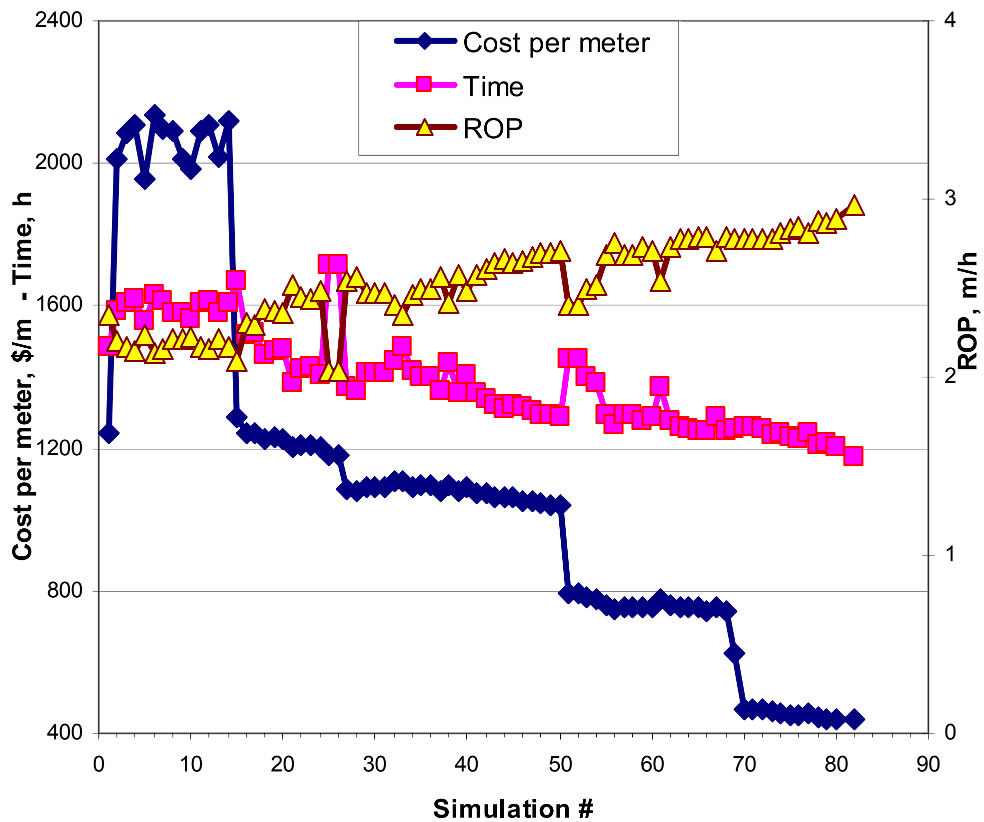


Fig. 31- Cost per meter and time show a tendency to decrease and ROP to increase with new simulations.

Drilling Parameter Optimization

In the drilling parameter optimization step, the AI module was used to obtain the best combination of WOB and RPM for each bit. The parameters were constrained to some maximum values associated with the rig capacities (RPM), bottomhole assembly, and directional control (WOB). The maximum values used in this research for these parameters were a 130 rpm of rotational velocity using the rotary table and 25 ton of WOB. The number of steps for the optimization was established at a maximum of four to reduce the computational time and resemble a typical trend of drilling with four drill-off tests during the run of each bit.

Fig. 32 illustrates the effects of the parameter optimization for bits 1, 2, and 3 simulated at the San Antonio/Querecual formations. The results show an increase of 14.6% on ROP using the optimum WOB and rotational velocity (**Table 19**).

The general tendency observed for all simulations optimizing parameters was that use of maximum WOB available with least rotational velocity increase ROP reducing time and cost.

TABLE 19—EVALUATION OF IMPACT OF DRILLING PARAMETER OPTIMIZATION ON BIT PERFORMANCE

Bit Type	Run	ROP m/h	Cost per meter $/m	Variation %	ROP m/h	Variation %
Three Cone 435	1	3.2	336.6			
	2	7.0	172.2	-	2.9	-
	3	4.0	301.0			
Three Cone 435 w/ Optimized Parameters	1	5.1	241.0	28.4		
	2	7.0	172.2	0.0	3.1	5.1
	3	4.4	299.4	0.5		

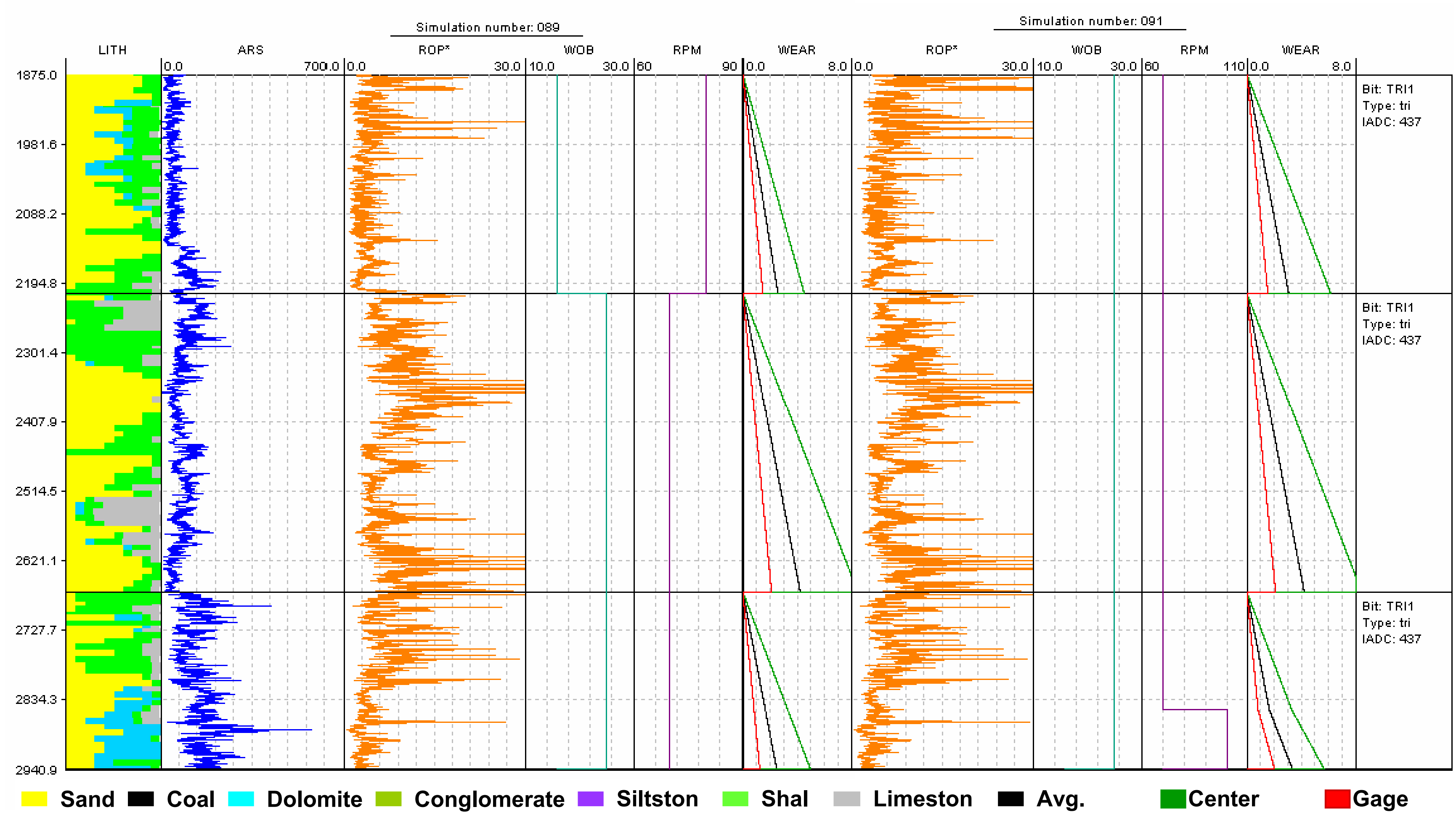


Fig. 32- Comparison between simulations with and without optimum drilling parameters shows an increment of the ROP for the San Antonio/Querecual formations.

BIT PROGRAM PROPOSAL

The following is a summary of achievable bit performance on the next Bosque well. The proposal is based on the performance observed in the DL-1 well optimized using the DROPS® program. It is important to note that the actual performance will vary on the next well, as the formation characteristics will vary. With additional information and the use of the simulator, further improvements can be achieved.

The proposal is based on running higher WOB from 15 to 25 tons and generally lower rotational velocity (RPM) from 110 to 70 RPM. If less WOB and more RPM are required for deviation control proposes, the bit program will require a new optimization using the DROPS® simulator.

Table 20 contains the total of 21 bits and the principal drilling parameters for each run.

TABLE 20—BIT PROPOSAL FOR NEXT WELL IN BOSQUE FIELD, ALOCTONO 12-1/4-IN. SECTION

Bit N	IADC Bit	Depth in m	Depth out m	Distance m	WOB ton	RPM rev/min	Rotational Time, h	ROP Estimated, m/h
1	435	1875	2210	335	15-20	80	80	4.2
2	435	2210	2670	460	15-20	70	65	7.0
3	435	2670	2940	270	20-25	100-110	68	4.0
4	435	2940	3140	200	20-25	70	50	4.0
5	517	3140	3320	180	15-20	70	73	2.5
6	447	3320	3514	194	20-25	70	49	4.0
7	517	3514	3666	152	20-25	70	58	2.6
8	517	3666	3806	140	20-25	70-80	50	2.8
9	435	3806	4000	194	20-25	80-90	59	3.3
10	517	4000	4158	158	15-20	80-90	40	4.0
11	517	4158	4282	124	20-25	80-90	41	3.0
12	517	4282	4446	164	20-25	70-80	47	3.5
13	517	4446	4570	124	20-25	70-80	69	1.8
14	517	4570	4660	90	20-25	70-80	56	1.6
15	517	4660	4830	170	20-25	70-80	68	2.5
16	517	4830	4930	100	20-25	70-80	51	2.0
17	517	4930	5030	100	20-25	70-80	71	1.4
18	517	5030	5130	100	20-25	70-80	53	1.9
19	517	5130	5200	70	20-25	70-80	39	1.8
20	517	5200	5270	70	20-25	70-80	34	2.1
21	517	5270	5360	90	20-25	70-80	46	1.9

CONCLUSIONS AND RECOMMENDATION

CONCLUSIONS

The following conclusions are derived from this study:

1.-This research was conducted to evaluate the benefits and practical application of the drilling simulation technology. We have found in the literature that is possible predict the drilling performance on the basis of a combination of theoretical and lab drilling models.

2.-Different companies are developing and using drilling simulators in the planning and drilling of oil wells. The results show that a drilling simulator can accelerate training, increase the use of the best technology, and shorten the drilling learning curve. After a set of wells is drilled, the experience can be captured and retained. The drilling simulator can generate a complete model of the drilling process, so the engineers can run multiple scenarios quickly and update the plans with the new data to predict the consequences of their decisions.

3.-The DROPS® software is a drilling simulator that has the capacity to simulate the drilling process as function of the ARSL. Our research has shown the software accuracy in the prediction of the unconfined rock strength based on drilling and lithology data (compared with unconfined rock strength estimated from electric logs).

4.-Our work validates the use of drilling models for the three-cone bit, PDC and ND based on rock strength to predict the ROP of a drilled well with high accuracy from field data.

5.-Our evaluation of drilling conditions of the DL-1 well with respect to the mud program shows a window of opportunity to increase the ROP of the 12-½-in. section by reducing the mud weight. A new mud program will allow a reduction in drilling time, increase of ROP, and reduction of cost per meter.

6.-With its basics in the simulations run with DROPS®, our research shows that the PDC and ND bits available are not the best option for the Aloctono formation. The use of tree-cone bit allows a lower cost per meter without losing drilling velocity (ROP).

7.-The drilling parameters analysis showed that WOB and ROP are critical in drilling optimization. Our research shows that using the maximum WOB available and reducing rotational velocity of the bits increase their performance in the Aloctono block.

8.-The use of DROPS® drilling simulator software as an optimization tool allowed selection of new mud and bit programs with better cost per meter, ROP, and drilling time.

RECOMMENDATIONS

We recommend the following:

- Use drilling simulators during the planning and drilling of hydrocarbon wells as good practice. Data bases of simulated wells need to be established as a knowledge source and as a practical training method.

- Evaluate performances of different bit types using drilling simulators as practical tools for the decision making.

- Drill the Aloctono block section of the Bosque field using three-cone bits. The use of drag bits needs to be limited as their cost per meter is high.

- Drill the Aloctono block using the maximum WOB available and minimum rotational speed. In the case that directional controls are required, the use of more aggressive bits is recommended.

- Create and evaluate specific PDC and ND bit designs for the Aloctono on the basics of the drilling simulator results. The advantage of the PDC and ND bits will increase the safety of the drilling operation.

- Use the new mud and bit program designed with DROPS® simulator for drilling new well in the Aloctono block of the Bosque field with similar characteristics to DL-1.

NOMENCLATURE

A	=	independent polynomial factor, dimensionless
A_e	=	effective pumpoff area, in.^{2}
A_p	=	vertical projected cutter area, in.^{2}
A_{rabr}	=	relative abrasiveness, dimensionless
A_v	=	area compressed in front of cutter, in.^{2}
A_{v_w}	=	area lost to wear of the cutter, in.^{2}
a	=	bit coefficient, dimensionless
a_c	=	chip hold-down coefficient, dimensionless
a_d	=	drag-bit lithology coefficient, dimensionless
a_s	=	rock-strength lithology coefficient, dimensionless
B	=	first order polynomial factor, dimensionless
b	=	bit coefficient, dimensionless
b_c	=	chip hold-down coefficient, dimensionless
b_d	=	drag-bit lithology coefficient, dimensionless
b_s	=	rock-strength lithology coefficient, dimensionless
C	=	second order polynomial factor, dimensionless
C_a	=	drag-bit wear coefficient, dimensionless
C_b	=	bit cost, US. $
C_f	=	cost per foot, US. $/ft
C_m	=	downhole motor cost, US. $/hr
C_r	=	rig cost, US. $/hr
c	=	bit coefficient, dimensionless
c_c	=	chip hold-down coefficient, dimensionless
c_d	=	drag-bit lithology coefficient, dimensionless
D	=	diameter, in.

D_{bit}	=	bit diameters, in.
d_c	=	cutter diameter, in.
d_s	=	diameter of diamond stones, in.
$f_c(P_e)$	=	chip hold-down function, dimensionless
I_m	=	modified jet impact force, lb
KA	=	apparent nozzle area at the pumpoff point, psi
N_c	=	number of cutter, dimensionless
N_s	=	number of diamond stones, dimensionless
P	=	cutter penetration per revolution, in
P_d	=	diamond penetration, in.
P_e	=	effective differential or confining pressure, psi
P_h	=	mud column hydrostatic pressure, psi
P_p	=	pore pressure, psi
P	=	mud density, ppg
P_w	=	diamond penetration with wear, in.
p_d	=	pressure of drillpipe drilling, psi
p_{ob}	=	pressure of drillpipe off bottom, psi
q	=	flow rate, gal/min
R_e	=	equivalent bit radius, in.
S, S_i	=	confined rock strength, psi
S_o	=	unconfined rock strength, psi
t_c	=	time connection, hr
t_r	=	time rotating, hr
t_t	=	time traveling, hr
V_d	=	volume removed per revolution, in.^{3}
W	=	weight on bit, lbf
W_c	=	wear coefficient, dimensionless
W_f	=	wear function, dimensionless
W_h	=	hydraulic pumpoff force, lbf

α	=	PDC cutter siderake angle, degrees
ΔBG	=	change in the bit tooth wear, dimensionless
Δp	=	pressure drop beneath a diamond bit, psi
Δp_b	=	bit pressure drop at pumpoff point, psi
Δp_t	=	change in internal pressure of drillpipe, psi.
ΔD	=	distance drilled, ft
θ	=	PDC cutter backrake angle, degrees
μ	=	mud plastic viscosity, cp
ρ	=	mud density, lbm/gal
ϕ	=	cutter backrake angle, degrees

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VITA

Name	José G. Salas Safe
Birth	December 22, 1963, Anaco, Anzoategui State, Venezuela.
Address	Calle Colon # 5-73, Anaco, Anzoátegui State, Venezuela, Zip 6003
Education	Mechanical Engineering, July 1989 Universidad Central de Venezuela, Caracas, Venezuela. Master of Science Degree in Petroleum Engineering, December 2003 Texas A&M University, College Station, Texas, USA